Testimony of
Mark Newton Lowry

DELMARVA POWER & LIGHT COMPANY
TESTIMONY OF MARK NEWTON LOWRY
BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION
CONCERNING AN INCREASE IN ELECTRIC BASE RATES
DOCKET NO. 11-___

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1. Q: <u>Please state your name, position, and business address.</u>

A: My name is Mark Newton Lowry. I am the President of Pacific Economics Group ("PEG") Research LLC. My business address is 22 E. Mifflin Street, Suite 302, Madison, WI 53703. I am testifying in this proceeding on behalf of Delmarva Power & Light ("Delmarva" or "the Company").

2. Q: <u>What are your responsibilities in your role as company president?</u>

A: PEG Research is a company in the Pacific Economics Group consortium which specializes in regulatory economics and utility cost research. Our practice, which has four experienced PhD economists, is international in scope and has included projects in eleven countries. Our clients include utilities, regulators, and public agencies, and this has given us a reputation for objectivity and dedication to economic science. Alternatives to the traditional North American approach to regulation are a company specialty. We maintain a large library of documents on alternative regulation ("Altreg").

My duties as President of PEG Research include the management of the company, consultation on Altreg plans, supervision of statistical research, and expert witness testimony. I have testified numerous times on Altreg and utility performance. Venues for my testimony have included California, Colorado, the District of Columbia, Georgia, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri, Oklahoma, New Jersey, New York, Rhode Island, Vermont, Alberta, British Columbia, Ontario, and Quebec. I have for many years advised the Edison Electric Institute ("EEI") in Washington on Altreg issues. My resume is attached as Schedule MNL-1.

A recent focus of my work has been Altreg remedies for the chronic attrition that many utilities face today due to the kind of regulatory lag that traditional regulation produces under today's business conditions. I have advised clients on how Altreg can alleviate chronic attrition, helped them to design specific measures, and testified in support of measures on numerous occasions.

EEI has recently published two white papers that I wrote on regulatory lag issues. These are: *Forward Test Years for U.S. Electric Utilities* (2010) and *Innovative Regulation: A Survey of Remedies for Regulatory Lag* (2011). Copies of these papers are attached as Schedule MNL-2 and Schedule MNL-3.

3. Q: Please tell us about your earlier professional work.

A: Before assuming my present position I was a partner of Pacific Economics Group LLC for ten years and managed that company's Madison office. Prior to that, I worked for nine years at Christensen Associates, first as a Senior Economist and later as a Vice President. My career has also included work as an academic economist. I was for several years a professor of mineral economics at the Pennsylvania State University and was a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal.

In total, I have twenty-seven years of experience as a practicing economist, spending the last twenty-one years doing work on gas and electric utilities. I hold a PhD in applied economics from the University of Wisconsin. I have numerous professional publications, been a referee for several scholarly journals, and chaired numerous conferences on Altreg.

4. Q: <u>Are you familiar with the situation of northeastern power distributors such as Delmarva?</u>

A: Yes. Over the years I have undertaken Altreg and benchmarking projects in numerous northeastern states. I am currently testifying on regulatory lag and Altreg for Potomac Electric Power in the District of Columbia and for Atlantic City Electric in New Jersey and recently assisted Delmarva in a settlement conference on Altreg in Maryland. PEG Research actively monitors regulatory proceedings throughout the Northeast.

5. Q: <u>What is the purpose of your testimony?</u>

A: My testimony addresses the challenge of chronic attrition due to regulatory lag that Delmarva and many other energy distribution utilities face today under traditional regulation. I will explain the problem, describe the consequences, and discuss regulatory measures that mitigate regulatory lag. My testimony concludes by discussing the specific remedies that Delmarva is proposing for regulatory lag in this proceeding.

6. Q: <u>Please summarize your testimony.</u>

A: Regulatory lag is a serious obstacle to Delmarva's ability to earn its authorized (rate of) return on equity ("ROE"). The Company plans a sustained increase in its capital spending ("capex") over the next few years in order to modernize its infrastructure and improve reliability. The regulatory system under which Delmarva currently operates cannot provide it with the timely rate relief it needs to undertake this initiative without chronic underearning.

Regulatory lag is a common problem today for gas and electric power distributors that operate under traditional regulation and are engaged in accelerated modernization programs. Various Altreg measures are in use around the country which help to mitigate regulatory lag while preserving regulatory oversight and incentives for efficient management. I recommend that the Delaware Public Service Commission ("Commission") draw from the menu of options thus developed to reduce the regulatory lag facing Delmarva. The best steps that the Commission can take in this proceeding are to approve some combination of a Reliability Investment Recovery Mechanism ("RIM") and a multi-year rate plan to begin after new rates are set and to approve the use of fully forecasted test years in future Delmarva proceedings.

7. Q: Please explain the concept of regulatory lag and why it should matter to regulators.

A: Regulatory lag is the delay between the time when a utility's ROE deviates from the target set by regulators and the time when an offsetting rate decrease or rate increase is implemented. When the ROE is below the target, regulatory lag prolongs underearning.

Regulators have the job of ensuring that the terms of utility service are just and reasonable. This is usually understood to mean rates that give the utility a fair chance of earning its target ROE with good management. This just and reasonable standard is not met when a combination of regulatory lag and external business conditions creates an environment where a utility making sound economic choices experiences chronic underearning. This is unfortunately the situation that Delmarva will face during its accelerated modernization program if there is no reform in the Commission's largely traditional approach to the Company's regulation.

8. Q: **<u>Please explain why an energy distributor might experience chronic underearning under traditional regulation.</u>**

A: Chronic underearning is likely to occur when a regulatory system cannot produce revenue growth sufficient to compensate a utility for its cost growth. Between rate cases, the base rate revenue of a utility under traditional regulation is driven only by growth in billing determinants such as the volume of deliveries and the number of customers served. The "horse race" between cost and billing determinants thus determines the need for attrition relief. Cost growth can exceed the growth in billing determinants for reasons that are beyond utility control. To understand how this might occur in the energy distribution business it is constructive to consider the external business conditions that affect the growth of a distributor's cost and billing determinants.

The cost of a utility or any other business is driven chiefly by three factors: input prices, productivity, and operating scale. My statistical research over many years has revealed that the number of customers is the principal dimension of operating scale that drives the cost of energy distributors in the short and medium term. These considerations lead to the following Distributor Cost Growth Formula, which has been acknowledged by regulators:

growth Cost = growth Input Prices - growth Productivity + growth Customers.

It can be seen that two of the biggest drivers of an energy distributor's cost --- inflation and customer growth --- are substantially beyond its control. Productivity can be influenced by distributors since they can by their own initiative reduce their inefficiency. However, productivity growth is also influenced significantly by external business conditions such as changes in technology and facility undergrounding requirements. Productivity growth can be accelerated by a well-managed merger or acquisition but is temporarily slowed by an accelerated modernization program since this causes the rate base to grow more rapidly. A slowdown in productivity growth causes cost to grow more rapidly.

9. Q: <u>What external business conditions drive the growth in billing determinants?</u>

A: Under traditional rate designs, the costs of most US energy distributors are recovered chiefly by the usage (*e.g.* volumetric and peak demand) charges of residential and commercial ("R&C") customers. The growth of revenue is thus quite sensitive to the trend in R&C system use, whereas customer growth drives cost growth. The trend in system use depends mostly on changes in external business conditions such as income levels, the penetration of energy using appliances, appliance efficiency standards, building codes, and demand-side management ("DSM") programs.

10. Q: <u>What are the implications of this analysis?</u>

A: From the perspective of an energy distributor, two factors cause cost to grow more rapidly than billing determinants, triggering a need for rate escalation. One is the gap between input price inflation and productivity growth. The other is the tendency of growth in R&C system use to outpace customer growth. The difference between the growth of R&C system use and customers is sometimes called the growth in "average use". Thus, the following formula explains how external business conditions drive the growth in energy distribution base rates that is needed to avoid attrition:

growth Rates = (*growth Input Prices* – *growth Productivity*)

\- *growth Average Us*e.

11. Q: <u>What is known about the input price and productivity trends of energy distributors?</u>

A: The growth in the productivity of most firms in the economy --- conventionally measured by (total factor) productivity indexes --- is typically a good bit slower than the inflation in the prices they pay for inputs. That is why prices of most goods and services tend to rise over time. Energy distributors are no exception. Table 1 and Figure 1 detail new estimates that I have prepared of the input price and productivity trends of a large group of energy distributors in the Northeast U.S. This comparison demonstrates that, for the Northeast as a whole, the input price inflation facing power distributors exceeded growth in their productivity by an average of about 255 basis points annually from 1999 to 2010.

Table 1

Trends in the Input Prices and Productivity of Northeast Power Distributors

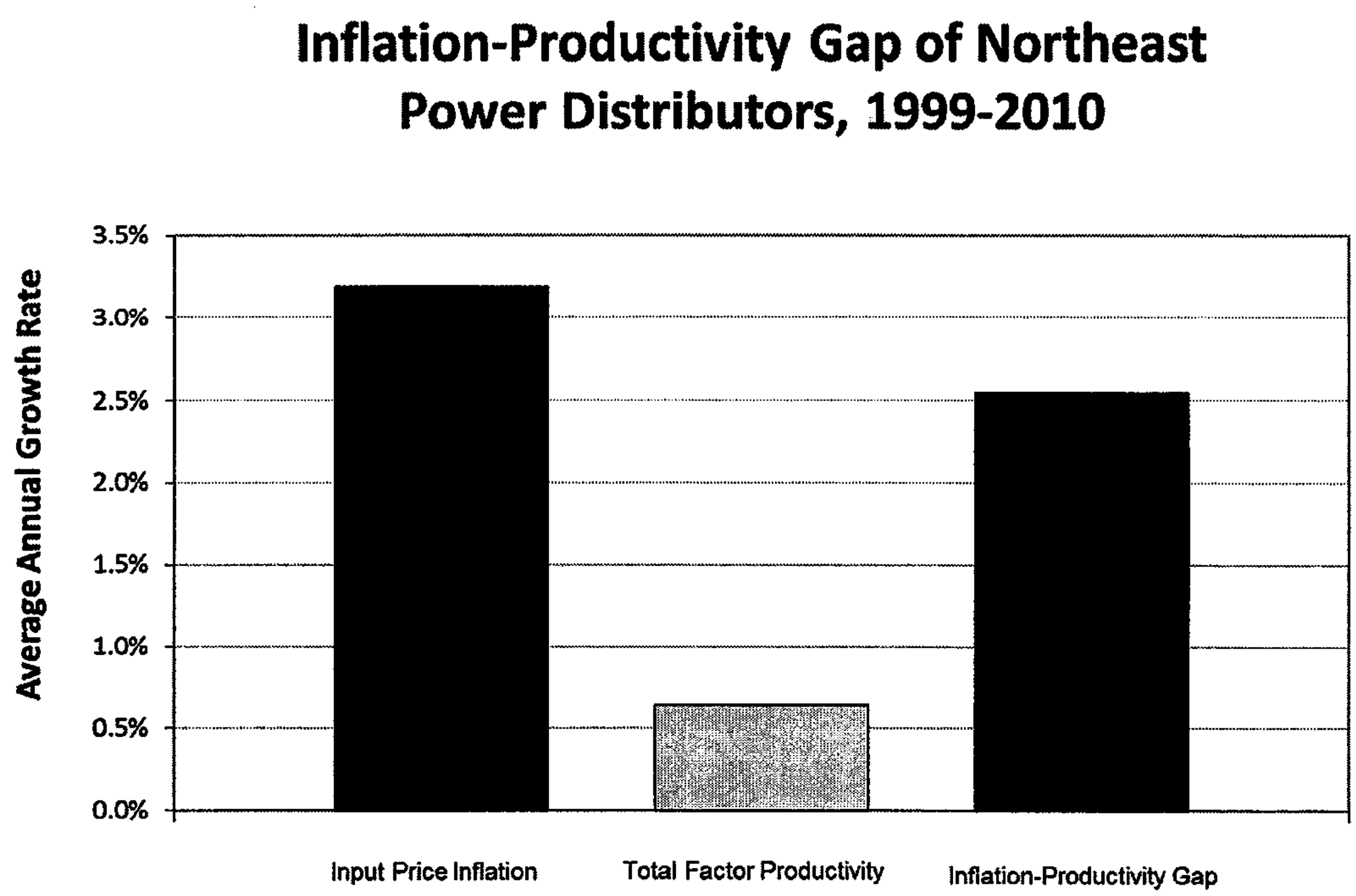
Year	Input Price Inflation [A]	Total Factor Productivity Growth [B]	Inflation-Productivity Gap [A - B]
1999	2.76%	-0.30%	3.06%
2000	2.47%	3.76%	-1.29%
2001	3.58%	-1.40%	4.98%
2002	2.92%	2.26%	0.66%
2003	3.70%	-1.71%	5.42%
2004	2.29%	3.96%	-1.68%
2005	3.31%	-0.12%	3.43%
2006	3.21%	1.46%	1.76%
2007	2.72%	-0.87%	3.59%
2008	3.37%	0.44%	2.94%
2009	4.38%	1.73%	2.66%
2010	3.51%	-1.52%	5.03%
Average Annual Growth Rate			
1999-2010	**3.19%**	**0.64%**	**2.55%**

Data Sources: FERC Form 1 (power distributor cost and bond yield), Form EIA-861 (customers), US Bureau of Labor Statistics (labor price indexes), Global Insight (power distributor material and service price indexes), Whitman, Requardt & Associates (power distribution construction cost index), and Regulatory Research Associates (electric utility allowed ROE)

Northeast Sample: Atlantic City Electric, Baltimore Gas & Electric, Bangor Hydro-Electric, Central Maine Power, Central Vermont Public Service, Connecticut Light & Power, Consolidated Edison, Duquesne Light, Green Mountain Power, Jersey Central Power & Light, Maine Public Service, Metropolitan Edison, NSTAR Electric, Orange & Rockland Utilities, PECO Energy, Pennsylvania Electric, Pennsylvania Power, Potomac Electric Power, Public Service of New Hampshire, Public Service Electric & Gas, Rochester Gas & Electric, United Illuminating, West Penn Power, and Western Massachusetts Electric

Under typical operating conditions, it follows that the trend in the average use of energy by R&C customers which an energy distributor experiences is crucial to its need for rate relief. If average use is growing *briskly* (*e.g.* by 2% annually), the usual gap between inflation and productivity growth can be largely offset and rate cases can be avoided for several years at a time. If average use is

Figure 1



static, however, there are no additional margins to offset the inflation-productivity gap and rate cases will be needed fairly frequently. If average use is *declining*, rate cases will be needed frequently, and possibly annually.

The need for attrition relief will be even greater when the inflation-productivity gap is especially wide. In the case of an energy distributor, for example, accelerated modernization spurs rate base growth, thereby slowing productivity growth. The inflation-productivity gap is also widened in a period of rapid inflation.

12. Q: <u>Has the ability of average use to help utilities avoid underearning changed over time?</u>

A: Yes. U.S government data on trends in the average volumes of power used by residential and commercial customers are found in Table 2. This table shows that, for more than two decades after World War II, average use by R&C customers grew rapidly. Since, additionally, inflation was typically slow in these years, electric utilities needed very little rate escalation to avoid financial attrition. Rate cases were rare, and since growth in cost and billing determinants was fairly balanced, it usually made sense to set rates using the cost and output in a recent historical test year.

Table 2

TRENDS IN ANNUAL ELECTRICITY USE BY U.S. RESIDENTIAL & COMMERCIAL CUSTOMERS, 1926-2010

Year	Residential Average Growth Rate	Commercial Average Growth Rate
1927-1930	7.06%	6.67%
1931-1940	5.45%	2.00%
1941-1950	6.48%	5.08%
1951-1960	7.53%	6.29%
1961-1970	6.13%	9.51%
1971-1980	2.45%	3.07%
1981-1990	0.63%	1.40%
1991-2000	1.15%	1.68%
2001-2010	0.75%	0.23%

Sources: U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

Growth in average use fell markedly in ensuing decades. This coincided with rapid price inflation in the 1970s and early 80s, and the combination caused a sharp increase in the frequency of rate cases. The need for rate relief in the 1990s and early years of the new century was offset by two circumstances. First, input price inflation slowed markedly from the pace of the seventies and eighties. Second, most utilities were still vertically integrated and were not building new base load power plants. This slowed the growth in their rate bases and accelerated their productivity growth.

13. Q: <u>Does the situation of energy distributors today differ from this?</u>

A: Yes. Energy distributors that are not vertically integrated generally do not experience declining rate bases that might accelerate their productivity growth because they make their plant additions more gradually over time as the urban areas that they serve expand. As I have shown, the typical productivity growth of power distributors in the Northeast has in recent years been somewhat below that of the U.S. private business sector as a whole. Meanwhile, growth in the average use of power by residential and commercial customers has been fairly slow in the Northeast. Many natural gas distributors have endured material *declines* in residential and commercial average use for more than a decade.

14. Q: <u>What is the upshot of your analysis?</u>

A: The persistent gap between inflation and productivity, along with static or declining average use, means that energy distributors need steady rate escalation to avoid underearning. The need for rate relief is exacerbated for distributors engaged in accelerated modernization.

15. Q: <u>Why is traditional regulation an inadequate remedy for business challenges like these?</u>

A: The traditional remedy for persistent attrition is to file frequent rate cases. This approach does make rates more reflective of trends in business conditions, and gives the regulatory commission, its staff, and interveners an opportunity to monitor the company's activities. However, frequent rate cases have several drawbacks. First, a rate case is a lengthy process that is expensive to all parties in the proceeding, and ultimately to customers. Utility performance incentives are weakened. Infrequent rate cases give senior managers more time to devote to the basic business of providing quality service cost-effectively. Regulators have more time to devote to other tasks as well.

It is also important to consider that the outcome of a rate case is not known to the utility until its conclusion, while capital planning decisions require that the utility make decisions based on expectations of expenditures and returns forecasted far into the future. The prospect of frequent rate cases increases the uncertainty about the return that the utility can expect on its investment. The "risk premium" associated with frequent rate cases can raise the cost of financing investments. For example, a recent downgrade by Moody's in the credit rating for Central Hudson Gas & Electric was attributed in part to that company's increased dependence on frequent rate filings in a period of high capex. To make matters worse, frequent rate cases do not provide sufficient relief for an energy distributor when they are based on historical or hybrid test years, since these test year approaches do not fully account for the tendency of cost growth to exceed the growth of billing determinants between the test year and the rate effective year.

16. Q: <u>What are the consequences of not being able to earn the authorized ROE?</u>

A: Large capex programs require access to capital markets, and the cost of such programs is increased when capital cannot be raised on reasonable terms. On the equity side, dilution can occur. On the debt side, the financial metrics considered by rating agencies can deteriorate and credit ratings may fall, raising the cost of borrowing funds. The investment community pays close attention to a utility's ability to pay its creditors.

17. Q: <u>Please summarize your views on why traditional rate regulation can lead to chronic underearning for utilities under contemporary operating conditions.</u>

A: Traditional rate regulation does not cope well with a business environment in which cost growth tends to exceed the growth in billing determinants. Rate cases must be held frequently, and these cases do not provide sufficient rate relief when they are based on historical or hybrid test years. Chronic underearning can result, and is especially likely during a campaign of accelerated modernization.

18. Q: <u>Should utility investors be guaranteed the ability to earn the ROE authorized by the commission?</u>

A: No. A guarantee is undesirable, because of its incentive ramifications, but investors should have a reasonable opportunity to realize the ROE target. In a period of high capital investment, investors will not have a reasonable opportunity to realize the ROE deemed to be appropriate by the commission.

19. Q: How does addressing the issue of chronic underearning benefit the company's customers?

A: More timely recovery of capital costs will continue to allow a utility to attract, at a reasonable cost, the funds needed for capex. This is particularly important during a program of accelerated modernization, since it is a period of high borrowing activity. Utilities that earn their authorized ROE are also more comfortable making the large new investments that may be needed for a modern, high performance system. Reducing regulatory lag therefore brings into line the desire of commissions and consumers for improved safety and service reliability with incentives for the utility to make needed capital expenditures.

Regulatory lag mitigation measures can also permit rate cases to be held less frequently. The costs to customers of rate cases are reduced. Executives will have stronger performance incentives and more time to devote to the basic business of providing quality service cost-effectively. Regulators will have more time to focus on other issues that matter to customers.

Consider also that some remedies for regulatory lag smooth out rate changes and the impact of large additions to rate base. The cost of these investments can be introduced into rates gradually rather than building up and coming into rates in large increments.

20. Q: Please apply your analysis to the situation of Delmarva.

A: Delmarva is the largest electric utility in Delaware. It built its last generating unit (at Hay Road) in 1993, and its cost growth during the 1990s was slowed by a declining generation rate base. This circumstance and mergers between Delmarva and other utilities helped it to operate without a rate increase for many years.

Like most electric utilities in the Northeast, Delmarva no longer operates generating plants and instead specializes in transmission and distribution. As a "wireco", the Company can no longer count on a declining generation rate base to accelerate its productivity growth. The distribution rate base has been growing for years.

Delmarva obtains the lion's share of its distribution base rate revenue from residential and commercial customers. Growth in residential and commercial average use has been fairly sluggish. DSM programs in Delaware are accelerating, and Delmarva is an active supporter of these programs, which are designed to reduce overall bills. Growth in average use cannot be counted on to offset much of the inflation-productivity gap, and the Company is likely to file rate cases fairly frequently under normal operating conditions. This case was filed little more than two years after the Company's last rate case filing. Rate case adjustments are made in seven months subject to refund, but a considerably longer period has recently been required before the Commission renders its final decision.

Delaware's current regulatory system involves rate cases with partially forecasted test years. The Company has under earned for several years. A report last year on Pepco Holdings by Fitch Ratings stated that "ratings concerns include persistent regulatory lag at the three utility subsidiaries that causes them to file frequent rate cases".[1] An August report on Pepco Holdings in SNL Energy's *Financial Focus* states that

> Regulatory lag continues to be an issue, as the company has consistently under-earned relative to its authorized returns on equity (ROEs), Consequently, rate case activity is expected to remain robust over the next few years.[2]

My analysis suggests that undertaking the accelerated modernization program without expedited capex cost recovery would worsen Delmarva's attrition problem. Annual or even more frequent rate cases would be likely, and the Company might reasonably request a higher cost of capital to compensate it for its risk.

21. Q: <u>What are some Altreg mechanisms that this Commission should consider to mitigate chronic attrition?</u>

A: There are numerous well established Altreg measures that, separately or in combination, could give Delmarva a better chance to earn the Commission-authorized ROE during its accelerated modernization program. In this testimony I focus on the four remedies for regulatory lag that are most widely used today: revenue decoupling, multi-year revenue caps, targeted cost recovery mechanisms, and fully forecasted test years. I will describe each of these lag-mitigation options, the precedents for them, and advantages and disadvantages of each.

[1] Fitch Ratings,. Fitch Rates Pepco Holdings' $250 MM 5-year 2.7% Notes 'BBB'; Outlook Stable", September 30, 2010.

[2] SNL Energy *Financial Focus*, "Pepco Holdings (POM)", August 26, 2011.

22. Q: <u>Please discuss first the revenue decoupling remedies for the problem of regulatory lag.</u>

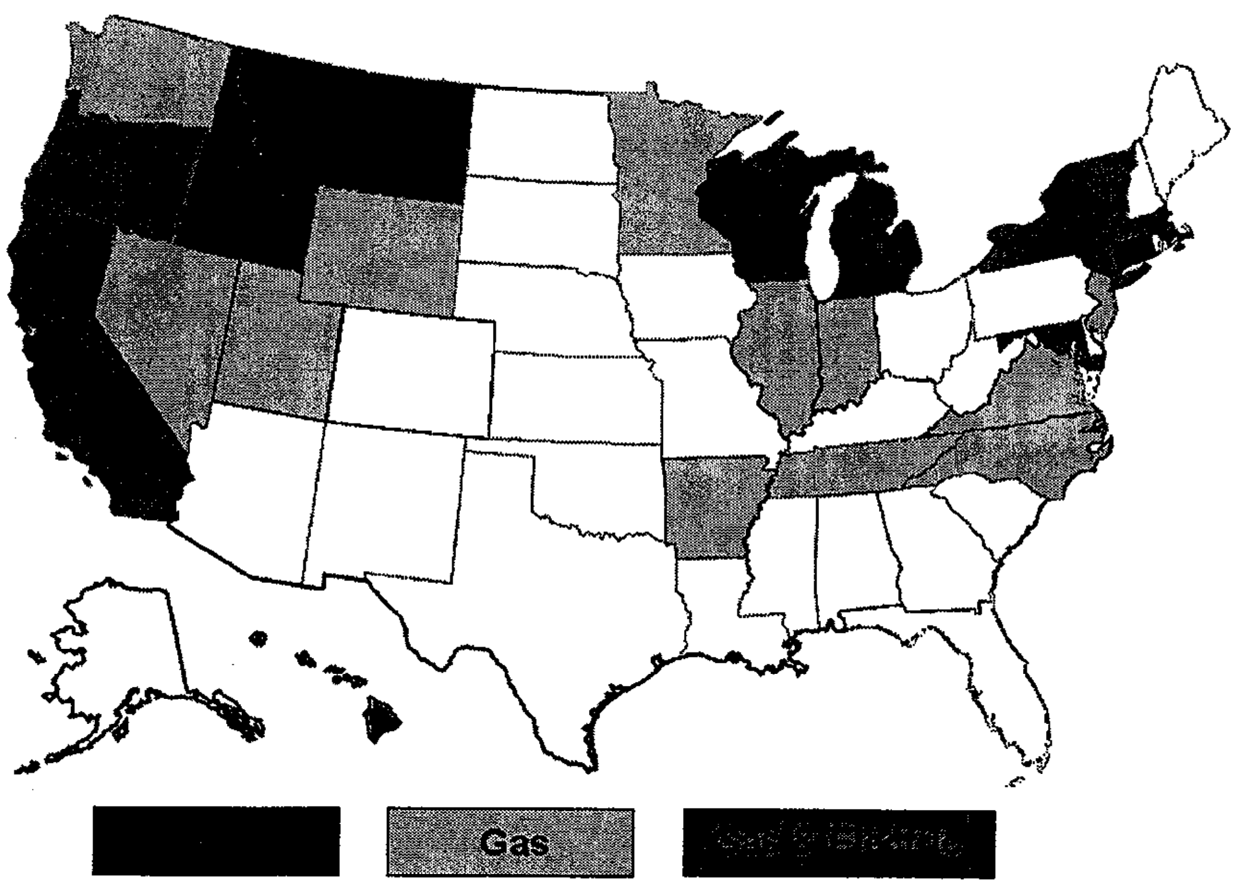
A: The term revenue decoupling refers to a group of regulatory provisions designed to weaken the link between a utility's revenue and the use of its system by customers to take delivery of energy. Decoupling can mitigate the financial attrition caused by utility DSM programs, thereby reducing disincentives to pursue DSM, and can also help with external conditions that cause average use to decline. Three approaches to decoupling are well established: decoupling true-up plans, lost revenue adjustment mechanisms ("LRAMs"), and fixed variable pricing.

This Commission's Staff, the Division of Public Advocate ("DPA"), Delmarva Power, & the Department of Natural Resources & Environmental Control ("DENREC") are currently in the process of developing a plan for fixed variable pricing for the Commission to consider. As for the other approaches, decoupling true-up plans help a utility's actual revenue track the revenue allowed by regulators. As with fixed-variable pricing, utilities are protected from *declines* in average use but are denied the benefit from any *growth* in average use.

23. Q: <u>What are the precedents for decoupling true-up plans?</u>

A: States that have gas and electric decoupling true-up plans are indicated on the map below in Figure 2. These include plans for Pepco in the District of Columbia and Maryland and for Delmarva Power in Maryland. The maps indicate that there are more plans for gas distributors than for electric utilities. This reflects the more pervasive character of the declining average use problem that gas distributors face. In the electric utility industry, decoupling true-up plans are most likely to be adopted in service territories where there is material decline in average use by R&C customers. Such declines are usually attributable to a large DSM program.

Figure 2: Gas & Electric Decoupling True-Up Plans by State

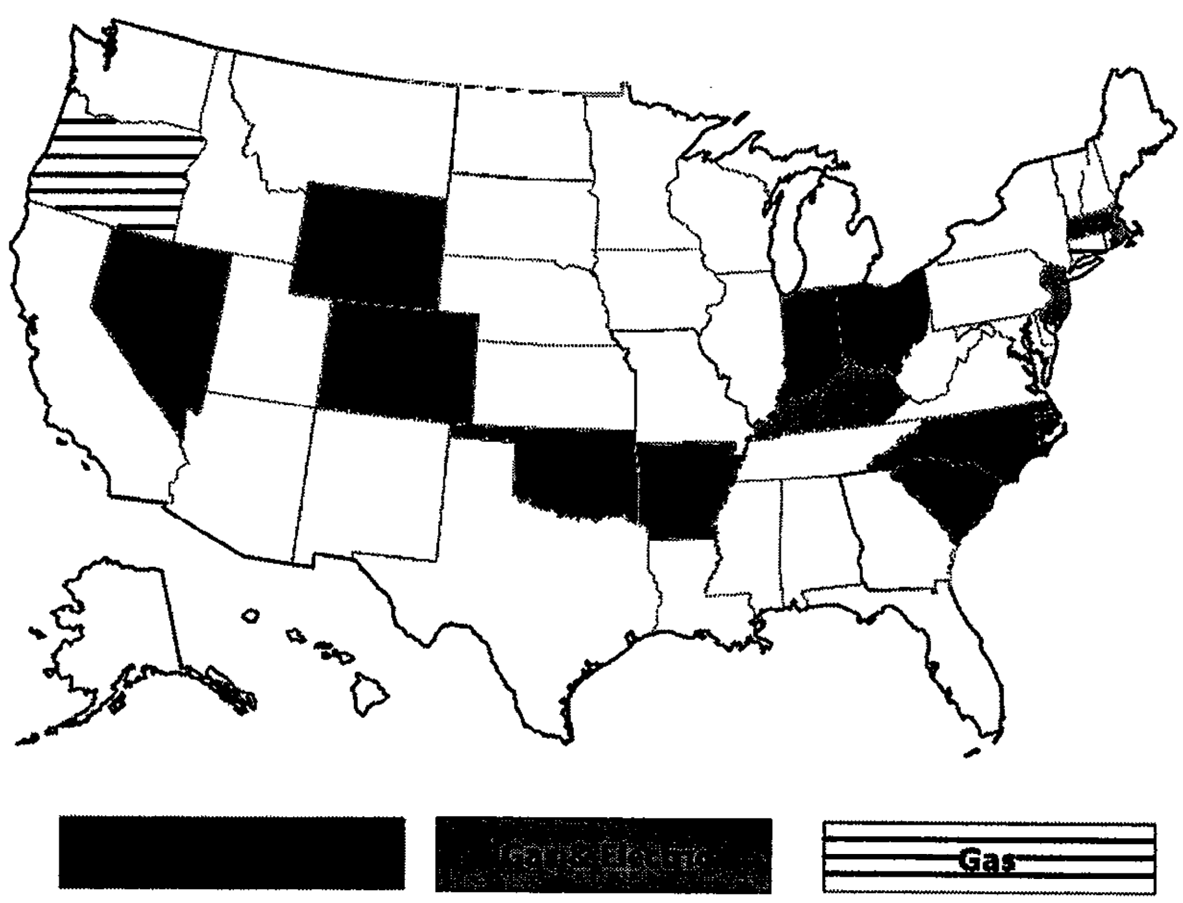


24. Q: <u>Please discuss the LRAM approach to decoupling.</u>

A: An LRAM explicitly compensates a utility for base rate revenues that are estimated to be lost due to its DSM programs. Compensation for lost margins is usually effected through a rate rider. Compensation is not confined to *declines* in average use, as it is under decoupling true-up plans and fixed-variable pricing. Any growth in average use that occurs notwithstanding DSM will alleviate underearning.

Precedents for LRAMs are detailed in Figure 3 below. It can be seen that LRAMs are less widely used than decoupling true-up plans today. One reason is that they are less useful for gas distributors, which experience declines in average use mainly for reasons other than the DSM programs that they administer. LRAMs have experienced a rebound recently due in part to their use in Duke Energy's "Save a Watt" approach to DSM regulation in several states.

Figure 3: Current LRAMs by State:



25. Q: <u>What are the pros and cons of revenue decoupling as a remedy for regulatory lag?</u>

A: Decoupling true-up plans and fixed-variable pricing both alleviate regulatory lag from declining average use. However, this feature is of no benefit to the many electric utilities that, like Delmarva, are not experiencing a *declining* trend in average use, and utilities are denied the financial benefit of any *growth* in average use such as might result from increasing popularity of electric vehicles.

LRAMs provide relief only for the financial effects of DSM programs and permit the utility to benefit from growth in average use from other sources.

26. Q: <u>Please describe multi-year plans and explain how they can alleviate chronic attrition.</u>

A: Multi-year rate plans are a form of incentive regulation which involve multi-year moratoriums on general rate cases. The length of such plans is typically three to five years, but plans as long as ten years have been approved. Many multi-year rate plans feature predetermined attrition relief mechanisms that provide rate relief for input price inflation and other changes in business conditions between rate cases. Predetermined attrition relief mechanisms can be designed to eliminate regulatory lag and provide funds needed for plant additions, including accelerated modernization programs. The rate adjustments are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* cost growth. This can strengthen incentives to contain cost growth. Benefits of the performance improvements that are stimulated by the plan can be shared with customers. The ability of multi-year rate plans to provide attrition relief without high regulatory cost or a weakening of performance incentives constitutes a remarkable advance in the "technology" of regulation.

Predetermined attrition relief mechanisms may cap the growth of allowed rates or revenue. Rate caps limit the escalation in rates (*e.g.* customer charges and cents per unit of power delivered). They are favored where utilities are encouraged to bolster system use, since rate caps strengthen incentives to promote use and can facilitate marketing flexibility by reducing concerns about cross subsidization.

Revenue caps limit the escalation in allowed revenues. They are often favored over rate caps where DSM is encouraged and/or declining average use is a problem. A revenue cap must be accompanied by some means of converting the updated allowed revenue to rates. This conversion can take account of the trend in average use and this can mitigate utility disincentives to promote DSM. Revenue caps are sometimes accompanied by balancing accounts that ensure that allowed revenue is ultimately recovered. However, this extra step need not be taken.

Multi-year rate and revenue caps commonly allow supplemental rate adjustments for changes in external business conditions that were especially difficult to anticipate at the time the plan was fashioned. These include changes in tax rates and other government policies (*e.g.* conductor undergrounding requirements and highway relocations) that affect costs. Some multi-year plans also feature earnings sharing mechanisms that share earnings surpluses and/or deficits that result when the ROE deviates from its regulated target. Plans also sometimes feature award and/or penalty mechanisms that are linked to service quality metrics.

27. Q: <u>How are predetermined attrition relief mechanisms designed?</u>

A: Several kinds of attrition relief mechanisms have been established. The most common approaches are indexing, stairsteps, and hybrids. A price cap index has the following general form:

Growth Prices = Inflation – X.

In North America the term X in this formula, the "X factor," often reflects a productivity growth target that is developed with research on the productivity trend of a regional or national group of utilities. The indexing approach is more likely to be used where no capital spending surge is anticipated, which would complicate calculation of a productivity target.

The stairstep approach to the design of an attrition relief mechanism provides predetermined fixed increases in allowed revenue which are often based on forecasts of cost growth. For example, revenue might be scheduled to grow 4% in the first year, 6% in the second, and 2% in the third year of a three year plan. One advantage of this approach is that it can easily accommodate the high capex that might result from accelerated modernization. Stakeholders are compelled to consider a multi-year capex budget, and are given the opportunity that a rate case provides to weigh in on its details. Customers may value knowing in advance the schedule for future revenue increases. However, the stairstep approach does not, like the indexing approach, adjust rates automatically for unforeseen inflationary conditions such as might be triggered, for example, by an oil price shock.

28. Q: <u>Please explain the hybrid approach to design of an attrition relief mechanism.</u>

A: A hybrid approach involves a mix of indexing and forecasts. In North America, a hybrid revenue cap typically involves indexes for the component of allowed revenue that pertains to O&M expenses and stairsteps for the component that pertains to capital costs. The stairsteps for capital cost are sometimes fixed in real terms and then adjusted for construction cost inflation as measured by an energy utility construction cost index. A company called Global Insight has maintained input price indexes for utility O&M expenses and construction costs for many years, and these have been used several times in hybrid attrition relief mechanisms. Hybrid attrition relief mechanisms exploit the flexibility of stairsteps in accommodating capex upticks with the streamlining and hyperinflation protection that indexing provides for O&M expenses.

29. Q: Is the ROE typically reduced in return for approval of such a plan?

A: No, since any reduction in risk from the elimination of expected underearning is offset by the risk of operating for several years without a rate case.

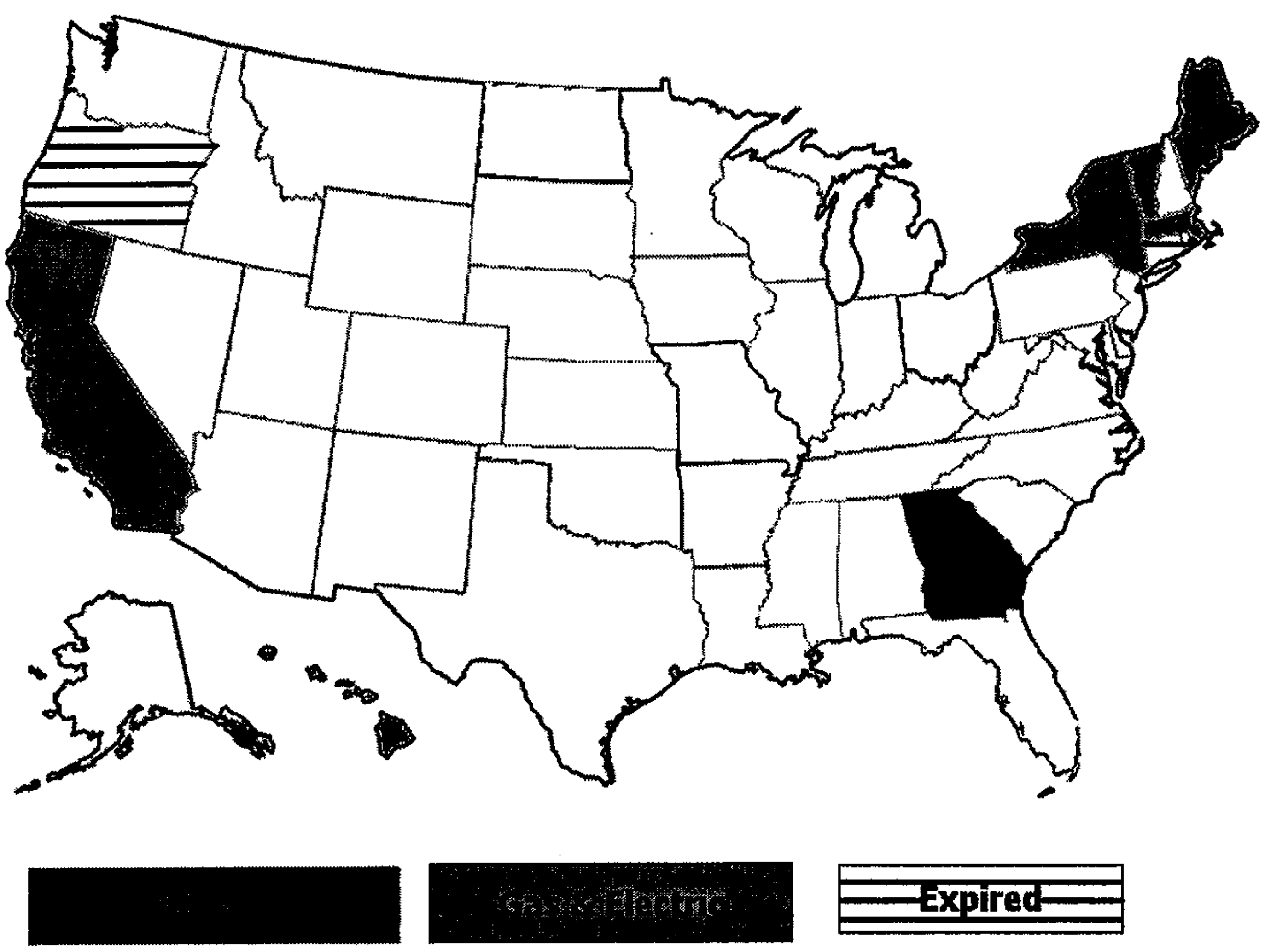
30. Q: What happens in the event that capital spending deviates from the budgets?

A: Under a multi-year rate plan the utility typically absorbs 100% of the annual costs of capex overspends, and keeps 100% of the annual cost savings from underspends. However, rates are reset in the next rate case to reflect the remaining net value of capital expenditures during the plan.

31. Q: What are the precedents for multi-year rate plans?

A: Recent precedents for multi-year rate plans of U.S. energy utilities are summarized in Figure 4. It can be seen that this kind of Altreg has to date been most common in California and the Northeast. It is used today primarily to regulate gas and electric power distribution. Multi-year rate plans are also popular for energy utilities in Canada. They are used to regulate all gas and electric distributors in Ontario and are also used in Alberta, Quebec, and British Columbia. The Alberta Utilities Commission recently directed all gas and electric power distributors to file multi-year rate plans following many years in which utilities filed rate cases every two years. Overseas, multi-year rate plans are more the rule than the exception for energy distributors. The "RPI (retail price index) – X" plans in Britain are especially well known.

Figure 4: US Precedents for Multi-year Rate Plans



32. Q: Why are multi-year rate plans more popular amongst energy distributors than amongst vertically integrated electric utilities?

A: This is due in part to the tendency of distribution cost to grow at a comparatively steady and predictable pace. This makes it easier for parties to agree on a predetermined rate adjustment mechanism. The popularity of rate and revenue caps for power distributors also reflects the fact that they need frequent rate escalation because they rarely experience the combination of *declining* rate base and *growth* in average use that might permit them to operate for several years under a rate freeze. Multi-year rate plans can thus sidestep the need for frequent rate cases over a recurrent set of issues, a situation that I sometimes call "Groundhog Day regulation". Comprehensive base rate freezes are still occasionally an option for vertically integrated electric utilities.

33. Q: <u>Which approaches to the design of a predetermined rate adjustment mechanism are most popular?</u>

A: Indexing is used in several New England states and Canadian provinces and is ubiquitous overseas, whereas stairsteps have for many years been used in Georgia and New York and have recently been used in California. The hybrid approach was developed in California in the early 1980s and has been used there by my count more than a dozen times. A revenue cap of hybrid design is currently used by Hawaiian Electric.

34. Q: <u>Please discuss the pros and cons of multi-year rate plans as a remedy for the chronic attrition that Delmarva faces.</u>

A: Multi-year rate plans are in my opinion the best approach to the mitigation of chronic attrition. Attrition from changing external business conditions can be eliminated without frequent rate cases. Regulatory cost is lower, and better utility cost management is encouraged. If accelerated modernization is planned the Commission, its staff, and stakeholders are compelled to consider the need for the investment and the appropriate multi-year budget. The revenue cap variant of a multi-year rate plan reduces utility disincentives to promote DSM.

The main challenge with a multi-year rate plan is the difficulty of agreeing to a predetermined attrition relief mechanism. This is a particular challenge for a jurisdiction with little experience, but the parties to regulation will gain expertise over the years. In California, for example, the parties to regulation have been negotiating these plans for almost thirty years due to a commission rule that limits the frequency of rate cases. In jurisdictions where there is significant concern regarding extreme earnings outcomes, an earnings sharing mechanism can be added to the plan. However, such mechanisms reduce the incentive benefits of the plan.

In an application to energy distributors it is, as I have said, generally not too difficult to agree on a predetermined attrition relief mechanism. In my opinion, the net benefits of multi-year rate plans will eventually become widely recognized, and such plans will become the most common approach to the regulation of power distribution utilities in the United States, as they are in other countries.

35. Q: <u>Have Commissions recognized the value of multi-year rate plans in avoiding frequent rate cases?</u>

A: Yes, the New York Public Service Commission stated in a recent rate case for Consolidated Edison that

> We generally prefer multi-year rate plans in instances where the terms are broadly seen to be better than those that might result from a litigated one-year rate case. In addition, we note that this proceeding includes many of the same, or similar, issues and major cost drivers as did the Company's last one-year electric rate case. These circumstances raise a significant concern that the public benefit might not be

> optimized if the upcoming Consolidated Edison electric rate filing--the third in three years--ultimately boils down to consideration of the same, or similar, issues on which parties largely just replicate arguments we have already carefully reviewed and either accepted or rejected. We also question how well the public interest may be served by the demands on time and resources of the Company, DPS Staff, and other parties in the face of continual annual rate proceedings.[3]

36. Q: Please discuss the option of fully forecasted test years.

A: A fully forecasted test year, sometimes called a future or forward test year ("FTY"), is a twelve-month period that begins after the rate case is filed. Most commonly, an FTY *begins* about the time that the rate case is expected to *end* and thus comes very close to matching the rate effective year. This typically involves forecasting cost about two years into the future. A more conservative approach, called a current FTY, is to begin the test period around the date of the rate case. This typically involves forecasting out about one year.

The forecasts used to make FTY cost projections are sometimes company budgets. Other utilities make a more detailed traditional cost filing for a historical reference year and then escalate many costs by mechanisms that are similar to those used to address attrition in multi-year rate plans. Global Insight forecasts of growth in power distributor O&M input price and construction cost indexes are useful for this.

The use of a forward test year would permit Delmarva's rates to more accurately reflect expected input price inflation and customer growth in the rate effective year. It would also allow for earlier inclusion of capital projects in base

[3] New York Public Service Commission, Order, 08-E-0539, April 24, 2009 p. 282.

rates because under a forward test year the costs of all projects can be included in rates which are likely but not certain to be finished during the rate effective year.

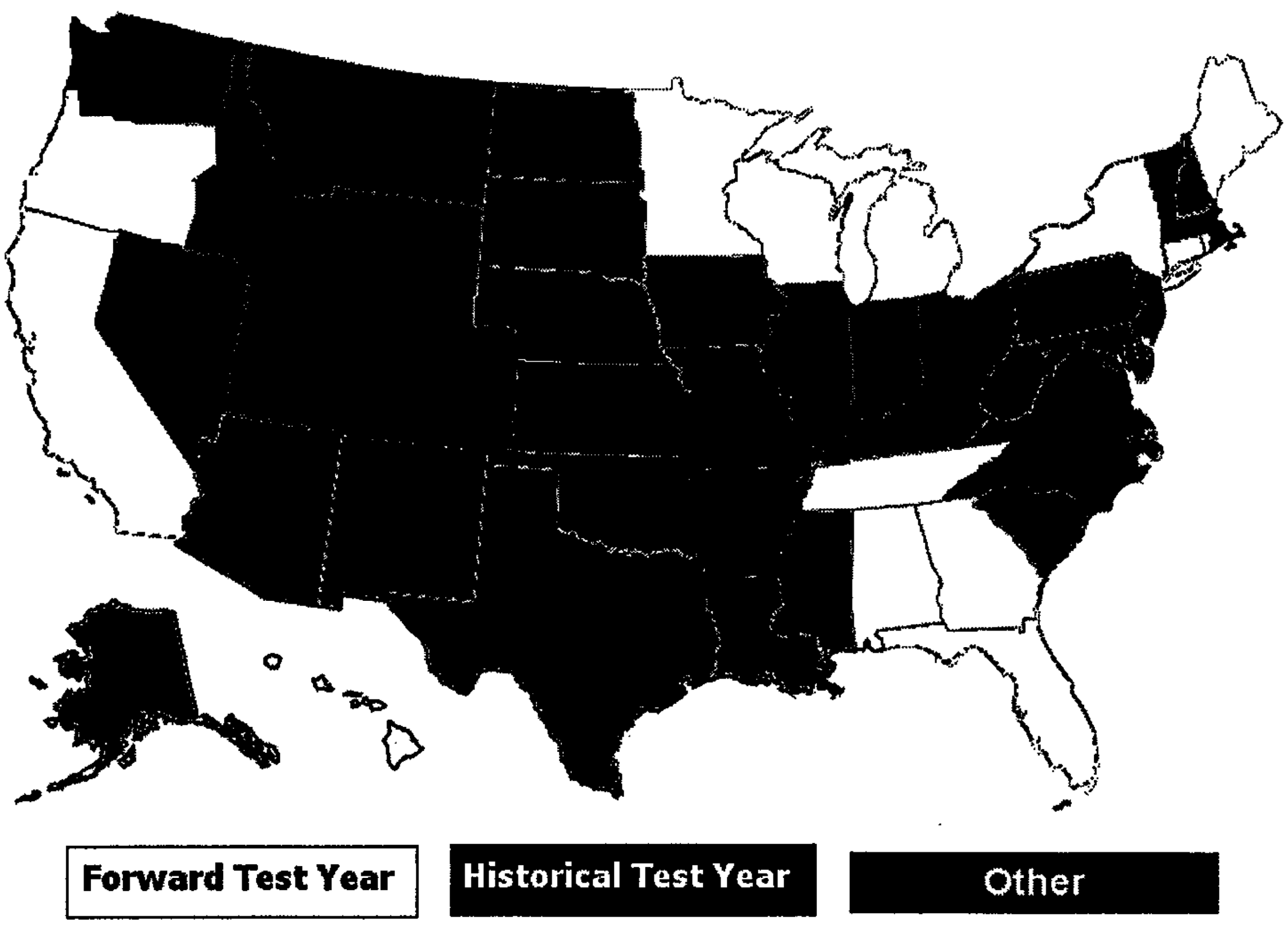
37. Q: <u>What are the precedents for forward test years?</u>

A: We have already noted that historical test years made sense in the early decades of the postwar period when cost growth was more similar to growth in billing determinants. Forward and hybrid test years were adopted in many jurisdictions during the 1970s and 1980s when rapid input price inflation coincided with slower growth in average use. The Delaware Commission sanctioned use of an FTY in a 1983 Delmarva Power & Light filing.

Commissions in several additional states have recently moved in the direction of FTYs. Many of these states are in the West, where comparatively rapid economic growth has required higher capital expenditures. However, the Illinois Commerce Commission ("ICC") recently accepted a return to forward test years in a rate case for Peoples Gas Light and Coke in Chicago. The company was undertaking an accelerated modernization program.

Current state policies concerning test years are summarized below in Figure 5. It can be seen that forward test years are the norm in twelve states. The "other" category in Figure 5 includes states that use a mix of historical and forward test years (*e.g.* Illinois), states that are transitioning towards forward test years (*e.g.* New Mexico and Utah), and jurisdictions like Delaware that use hybrid test years.

Figure 5: Test Year Policies by State



38. Q: <u>Please summarize the pros and cons of a forward test year.</u>

A: A forward test year can provide effective relief from the problem of chronic attrition. Capital can be obtained on more reasonable terms and rate shock can be avoided. Forward test years can also in some circumstances produce a reduction in the frequency of rate cases. In an application to a distributor with a sustained increase in capex, however, frequent and possibly annual rate cases are still quite likely with forward test years absent additional measures such as expedited capex cost recovery.

39. Q: <u>What would be a conservative way for this commission to move in the direction of a fully forecasted test year?</u>

A: To increase confidence in cost projections the Commission could require Delmarva to continue to file detailed, traditional cost evidence for a historical reference year with the usual known and measurable changes and ask that any additional escalation of cost to the forward test year be limited where possible to external index-based adjustments. These could use the custom Global Insight indexes of utility input price inflation which I discussed earlier. Utilities may, additionally, be asked to report retrospectively on the accuracy of their cost forecasts.

Another cautious step in the direction of forward test years would be to permit a *current* FTY with an *interim* rate that takes effect early in the proceeding subject to refund. This would effectively address the problem of regulatory lag without a two-year cost forecast. In Delaware, utilities already use a hybrid test year and can implement a rate increase equal to the lesser of 15% of the utility's intrastate revenues or $2.5 million, subject to refund, 60 days after filing a rate case. It is not a large step to move the test year forward several months and expand or eliminate the fixed dollar cap.

40. Q: <u>Are there ways to improve the effectiveness of hybrid test years in relieving regulatory lag?</u>

A: Yes. The Commission can extend the number of future months for which known and measurable changes are allowed. The Commission could also employ a terminal rate base rather than the average value of the rate base over the test period. During a time of high capex like Delmarva has initiated, and has plans to increase in future years, a terminal rate base is somewhat more reflective of the level of investment that is expected during the rate-effective period. It is, additionally, known and measurable prior to the time that the Commission issues its rate case decision.

41. Q: **Please explain the concept of targeted cost recovery mechanisms and address their advantages as remedies for regulatory lag.**

A: Targeted cost recovery mechanisms expedite recovery of particular costs outside of general rate cases. They are used in various situations where it is less practical to rely on general rate cases to adjust rates for changes in particular utility costs. For example, the energy costs of most utilities have been recovered with such mechanisms for years because the volatility and substantial size of these costs would otherwise lead to frequent general rate cases or elevated earnings risk. Other volatile costs that are sometimes recovered using targeted cost recovery mechanisms include those for pensions and uncollectible bills.

While the use of targeted mechanisms to recover volatile costs is well known and accepted, it is less widely recognized that under today's business conditions such mechanisms are also used to expedite recovery of costs that drive overall cost growth, irrespective of their volatility. This can mitigate any tendency of revenue growth to lag cost growth. It also reduces the frequency of rate cases because the residual cost that is recovered through conventional rates grows more slowly. Costs that are targeted for expedited recovery because of their impact on cost growth include those for health care, DSM, and capex.

Expedited capex cost recovery mechanisms recover costs of capex that causes growth in the rate base. The costs associated with the rest of the rate base, which are subject to recovery via conventional rates will therefore usually grow more slowly. The greater is the percentage of capex cost recovered by such mechanisms, the slower is the growth in the residual rate base. This reduces the need for rate cases. If the recovery of *all* capex is recovered contemporaneously, the residual rate base will certainly *decline*.

42. Q: **<u>Under what circumstances do regulators typically approve expedited recovery of capex costs?</u>**

A: Expedited recovery is most commonly approved for *major* capital spending programs. Major capex programs are undertaken for diverse reasons. Base load generation is a common type of major plant addition for vertically integrated electric utilities. Utilities engaged in transmission sometimes make large investments in new facilities to promote regional power trade or to access remote resources. Both kinds of investments can take more than a year to construct.

An allowance in rates for funds used during construction is traditionally not permitted until assets are used and useful. However, interest on these funds is added to the value of the asset that is ultimately added to the rate base. This allowance for funds used during construction ("AFUDC") produces extra interest expenses and rate "shock" when the rate base addition is ultimately made. The delay in receiving a return on investment reduces a utility's cash flow and increases its risk. The resultant higher cost of obtaining funds in capital markets also increases the cost of plant additions that customers ultimately pay. Many commissions address these problems by including costs of construction work in progress ("CWIP") in the rate base so that a return on investment can start sooner. Expedited capex cost recovery is often used in lieu of frequent rate cases to recover the return on CWIP.

43. Q: **What about energy distributors?**

A: For energy distributors, major capex programs are usually occasioned by an accelerated modernization program. These investments are typically made to improve metering capabilities and/or the reliability or (in the case of gas distributors particularly) the safety of service. Unlike capex for generation or customer connections, these kinds of investments don't naturally trigger new revenue when facilities become used and useful. The annual plant additions may not be as large as that for new or repowered baseload generation, and facilities become used and useful over a series of years instead of in one year. However, the annual expenditures can still be sizable. Under traditional regulation, utilities do not recover with interest the cost of past *depreciation* on new used and useful assets when they are added to the rate base. Timely recovery of the cost of accelerated modernization will therefore require frequent rate cases under traditional regulation. Expedited recovery of the accumulating annual cost of the new investment can help a distributor finance enhanced modernization without frequent rate cases or the rate shock and higher capital cost that can occur if rate cases are held less frequently. Expedited recovery of the cost of capex for generation emissions scrubbers has appeal for much the same reason, as a program to build scrubbers for several generating units often produces new used and useful equipment each year.

44. Q: Does this ratemaking treatment sometimes extend beyond accelerated capex to more routine capital expenditures?

A: Yes. In Ohio, for example, the three First Energy utilities are on their second round of expedited recovery of substantially *all* of their electric distribution capex costs. A similar approach is contained in a recent electric distribution settlement for the American Electric Power utilities in Ohio. In Texas, Atmos Pipeline and Centerpoint Energy Entex have mechanisms for expedited recovery of most capex costs called Interim Rate Adjustments. Texas law was recently revised to sanction a similar mechanism, called the Distribution Cost Recovery Factor, for electric distributors. Other utilities with unusually broad-based capex cost recovery mechanisms include Atlanta Gas Light, Cleco Power, and Duke Energy Ohio.

45. Q: What are the "capex costs" that are typically recovered by these mechanisms?

A: Most capex cost recovery mechanisms recover the accumulating annual capital costs that result from the targeted capex until a general rate case permits these costs to be recovered through conventional rates. The annual cost of capex includes a return on the value of the assets, depreciation on plant in service, and associated net taxes. The operation of a capex cost recovery mechanism thus requires a specification of the rate of return on plant and a depreciation rate. An adjustment is sometimes made for the retirement of plant that is occasioned by the capex.

46. Q: <u>In a rate case a test year must be chosen. How is this issue handled in expedited capex cost recovery?</u>

A: Many mechanisms are designed to recover a forecast of the capital cost in the upcoming year. Some mechanisms have more of a hybrid test year flavor. The mechanisms in several New Jersey plans, for instance, recover only the annual cost of the plant in service and CWIP in rate base at a date a few months prior to the implementation of the new capex recovery surcharges. This approach produces less attrition relief than the fully forecasted approach.

47. Q: <u>What protections would consumers have against an inaccurate cost forecast?</u>

A: Capex recovery mechanisms that feature cost forecasts usually involve a periodic (*e.g.* annual) reconciliation of the revenue gathered by the mechanism in previous years to an updated estimate of the cost that was incurred. The annual filing is for this reason often called a "reconciliation" filing even though it usually addresses several other issues.

48. Q: <u>How are deviations of actual capex from capex budgets treated?</u>

A: In most plans, underspends are passed entirely to customers and capex in excess of budgeted amounts is subject to eventual prudence review. However, the capex budgets in some plans are hard caps. In California where, as we have seen, experience with incentive regulation is quite extensive, sharing mechanisms are sometimes used in which positive and negative deviations from budgets in a prescribed range are shared mechanistically (*e.g.* 90%/10%) between customers and shareholders.

49. Q: <u>How is the integrity of reconciliation filings ensured?</u>

A: The accuracy of the filings can be addressed in the proceedings that review the filings and/or in the next general rate case. Additionally, some utilities have committed to periodic internal or external audits of these filings.

50. Q: <u>What attention is paid in expedited capex recovery mechanisms to the reasonableness of investments?</u>

A: Most expedited capex cost recovery mechanisms for energy distributors are the outcome of a proceeding in which a detailed multi-year investment plan is presented that includes the specific projects to be undertaken and an estimate of their cost. This gives the Commission an initial opportunity to appraise the increase in capex that gives rise to the request for expedited cost recovery.

The subsequent reconciliation proceedings may consider the reasonableness of updated forecasts of new projects and their costs. These proceedings are commonly assigned a window of a few months to be resolved. The proceedings usually allow for data requests, and some permit other parties to file testimony before the Commission makes its decision.

Costs and projects are, additionally, usually subject to a final commission review when the net plant additions are added to the rate base. When the capex recovery mechanism involves cost forecasts, these reviews usually occur in the next general rate case.

51. Q: <u>What protections are provided against rapid rate growth?</u>

A: In addition to the protections provided by commission reviews of capex costs and budgets, a few capex recovery mechanisms have featured "soft" caps that limit the revenue growth that can be triggered by the mechanism. Any shortfalls in the recovery of approved capital costs due to the cap can be recovered later with interest.

52. Q: <u>Please discuss the pros and cons of expedited capex cost recovery.</u>

A: Expedited capex cost recovery is a sensible remedy for the regulatory lag of an energy distributor engaged in accelerated system modernization. Underearning can be mitigated, reducing the cost of obtaining funds in capital markets. Annual rate cases are likely to be avoided if the distributor is, additionally, protected from material declines in average use. Regulation is thereby streamlined, and utility performance can be improved. In contrast to multi-year rate plans and forward test years, forecasts are required only for the targeted capex, and these forecasts are subject to annual reconciliations. Rate shock is mitigated. In summary, expedited capex cost recovery makes particular sense for commissions that want to encourage system modernization and recognize the potential for underearning but prefer not to mitigate the problem using salient alternatives such as forward test years.

One factor to address in the development of a capex recovery mechanism is the need to ensure that the capital spending that is thereby encouraged is appropriate by making sure that the capex is really needed and undertaken efficiently. These concerns can be mitigated by a well designed plan. Multi-year capex plans should reflect extensive evidence on the specific projects to be undertaken and their efficiency compared with alternative means of improving reliability. Plans should create a material risk that costs in excess of budgets will not be recovered, and perhaps also provide the utility with an opportunity to share in the benefit of underspends.

53. Q: <u>How does expedited capex cost recovery benefit electric distribution customers?</u>

A: More timely recovery of capex costs will continue to allow the Company to attract, at a reasonable cost, the capital that it needs for investments. This avoids potentially higher costs for customers and is particularly important in a period of high capex since more capital must be raised. Utilities that have a reasonable opportunity to earn their authorized ROE are also more comfortable making the large new investments needed for a modern, high performance distribution system. Reducing capex-exacerbated attrition therefore brings into line the desire of consumers for reliability and safety improvements with incentives for a utility to make the requisite capital expenditures.

Attrition mitigation measures also benefit customers by streamlining the regulatory process. The costs that customers ultimately pay for frequent rate cases are reduced. Executives will have more time to oversee the reliability improvement program and make sure that it improves the quality of service cost-effectively. Regulators are freed to focus on other issues that affect customers.

54. Q: <u>Has the ability of capex recovery mechanisms to reduce the frequency of rate cases been acknowledged by regulators?</u>

A: Yes. The ICC, for example, recently approved expedited capex cost recovery for an accelerated modernization program of Peoples Gas Light and Coke in Chicago. The ICC, in its decision approving the mechanism, acknowledged its superiority over alternative remedies such as frequent rate cases and regulatory assets. Concerning the former, it stated that

> From our perspective, rate cases consume vast amounts of time, money, and resources, and are not only burdensome for utilities and other parties. They also strain the limited resources of the Commission and its Staff and divert attention from other pressing matters. Ultimately too, rate case costs are consumer costs. We cannot and will not speculate on when the Company will need to come in for a rate case in the future, but it is reasonable to believe that Rider ICR may extend that period and to that extent, it is reasonable. Notably too, we do not see Staff or any other party to say that they prefer annual rate cases.[4]

55. Q: <u>Have you examined the impact of expedited capex cost recovery on capital costs?</u>

A: Yes. Table 3 presents selected credit quality metrics for a large sample of electric utilities that did and did not have capex recovery mechanisms over the 2008-2010 period. The source is *Credit Stats: Electric Utilities - U.S.* The report was prepared by Standard and Poor's ("S&P") and appears in the Global Credit Portal of its RatingsDirect service. I present results for four credit metrics: S&P's corporate credit rating, the (rate of) return on capital, and two cash flow ratios (EBITDA/interest coverage and FFO/Debt).

Cash flow ratios are used by credit analysts to assess a utility's ability to service debt. The cash flow measures in the numerators of these ratios are normally calculated as adjustments to net income that add back cash flows that could be used to service debt. FFO (funds from operations), for instance, adds

[4] Illinois Commerce Commission, *Order*, 09-0166 and 09-0167 Consolidated, January 21, 2010 pp. 173-174.

Table 3

How Electric Utility Credit Metrics Differ by Use of Capex Cost Recovery Mechanisms, 2008-2010

Company Name	S&P Corporate Credit Rating	Rate of Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Use Capex Cost Recovery Mechanisms				
Alabama Power	A	9.7	5.2	24.0
Appalachian Power	BBB	5.4	2.8	9.8
Cleveland Electric Illuminating	BBB-/BBB	7.1	3.7	13.9
Columbus Southern Power	BBB	13.0	5.6	25.1
Dayton Power & Light	BBB+/A-	15.2	13.5	49.9
Duke Energy Indiana	A-	7.9	5.4	18.9
Duke Energy Ohio	A-	5.9	7.4	27.8
Florida Power & Light	A-/A	9.5	6.9	32.5
Georgia Power	A	8.7	4.7	19.7
Indianapolis Power & Light	BB+/BBB-	N/A	N/A	N/A
Kansas Gas & Electric	BBB-/BBB	N/A	N/A	N/A
Kentucky Power	BBB	5.8	3.3	14.7
Kentucky Utilities	BBB+	N/A	N/A	N/A
Louisville Gas & Electric	BBB+	N/A	N/A	N/A
MidAmerican Energy	A-	7.6	4.8	25.9
Mississippi Power	A	10.2	8.4	31.7
Northern States Power MN	BBB+/A-	8.5	4.6	23.6
Ohio Edison	BBB-/BBB	9.8	3.8	19.1
Ohio Power	BBB	N/A	N/A	N/A
Pacific Gas & Electric	BBB+	9.3	4.8	22.0
PPL Electric Utilities	A-	7.8	4.9	23.0
Portland General Electric	BBB/BBB+	6.8	3.7	17.7
Progress Energy Florida	BBB+	9.6	4.2	16.4
Public Service Co. of Colorado	BBB+/A-	8.3	5.0	19.6
Southern California Edison	BBB+	9.9	4.2	26.0
Public Service Co. of Oklahoma	BBB	7.8	3.8	18.8
Toledo Edison	BBB-/BBB	8.0	3.2	10.4
Virginia Electric & Power	A-	8.8	4.5	19.6
Westar Energy	BBB-/BBB	6.4	3.7	15.4
Averages	**BBB+**	**8.6**	**5.1**	**21.9**
No Capex Cost Recovery Mechanisms				
Arizona Public Service	BBB-	7.3	4.5	22.4
Ameren Missouri	BBB-	7.2	3.7	20.2
Baltimore Gas & Electric	BBB/BBB+	5.6	4.0	22.4
Black Hills Power	BBB-	7.6	3.7	19.3
Central Hudson Gas & Electric	A	10.1	4.8	16.4
Connecticut Light & Power	BBB	7.7	4.8	15.1
Consumers Energy	BBB-	9.3	4.5	19.1
Detroit Edison	BBB/BBB+	9.0	5.0	21.5
Duke Energy Carolinas	A-	8.6	3.9	19.7
Duke Energy Kentucky	A-	7.7	6.1	25.1
El Paso Electric	BBB	9.3	4.0	20.8
Empire District Electric	BBB-	6.9	3.5	16.0
Entergy Arkansas	BBB	6.6	4.3	21.2
Entergy Gulf States Louisiana	BBB	7.6	3.5	25.1

Company Name	S&P Corporate Credit Rating	Rate of Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
No Capex Cost Recovery Mechanisms (continued)				
Entergy Louisiana	BBB	N/A	N/A	N/A
Entergy Texas	BBB	6.1	2.6	5.2
Green Mountain Power	BBB	N/A	N/A	N/A
Idaho Power	BBB	6.8	3.6	14.2
Interstate Power & Light	BBB+	8.0	4.9	25.3
Jersey Central Power & Light	BBB-/BBB	8.9	7.0	28.9
Kansas City Power & Light	BBB	6.6	4.0	15.3
Massachusetts Electric	A-	N/A	N/A	N/A
Monongahela Power	BBB-	N/A	N/A	N/A
Narragansett Electric	A-	N/A	N/A	N/A
Nevada Power	BB	6.7	2.5	11.0
Niagara Mohawk Power	A-	N/A	N/A	N/A
Northern Indiana Public Service	BBB-	8.3	7.5	26.5
Northern States Power WI	A-	8.9	6.1	30.9
Orange & Rockland Utilities	A-	N/A	N/A	N/A
PacifiCorp	A-	7.3	4.0	22.9
Potomac Edison	BBB-	N/A	N/A	N/A
Potomac Electric Power	BBB/BBB+	6.8	3.9	20.1
Progress Energy Carolinas	BBB+	11.0	5.5	29.1
Public Service Co. of New Mexico	BB-	4.5	2.4	15.3
Rochester Gas & Electric	BBB/BBB+	7.7	3.0	14.9
Sierra Pacific Power	BB	7.6	3.3	15.8
Southern Indiana Gas & Electric	A-	8.9	5.4	25.3
Southwestern Electric Power	BBB	7.0	2.8	15.8
Southwestern Public Service	BBB+/A-	6.7	3.4	13.8
Texas-New Mexico Power	BB-	5.7	3.4	18.6
Tucson Electric Power	BB+	8.8	3.8	17.6
West Penn Power	BBB-	N/A	N/A	N/A
Wisconsin Electric Power	A-	3.8	3.8	14.7
Wisconsin Power & Light	A-	9.4	4.4	26.2
Wisconsin Public Service	A-/A	9.9	5.7	28.7
Average	**BBB**	**7.7**	**4.3**	**20.0**
Indeterminate				
AEP Texas Central	BBB	6.8	5.0	19.2
AEP Texas North	BBB	7.5	4.3	21.1
Atlantic City Electric	BBB/BBB+	6.9	4.4	12.0
Central Maine Power	BBB+	7.3	4.8	21.0
CenterPoint Energy Houston Electric	BBB	8.5	4.9	20.2
Cleco Power	BBB	8.6	3.4	10.5
Commonwealth Edison	BBB-/BBB	6.2	3.5	17.5
Duquesne Light	BBB-	N/A	N/A	N/A
Entergy Mississippi	BBB	7.7	4.6	15.6
Entergy New Orleans	BBB-	10.7	5.1	28.4
Gulf Power	A	8.9	5.7	19.6
Hawaiian Electric	BBB-/BBB	6.9	4.4	15.5
Indiana Michigan Power	BBB	8.3	2.7	18.9
Metropolitan Edison	BBB-/BBB	7.4	5.5	21.7
NSTAR Electric	A+	10.4	7.6	22.5
Oklahoma Gas & Electric	BBB+	8.8	5.5	26.7
Oncor Electric Delivery	BBB+	8.9	4.0	15.6
PECO Energy	BBB	8.6	6.0	19.0
Pennsylvania Electric	BBB-/BBB	8.0	4.0	14.1
Pennsylvania Power	BBB-/BBB	N/A	N/A	N/A
Public Service Electric & Gas	BBB	8.3	4.9	20.3
Public Service Co. of New Hampshire	BBB	7.8	4.7	13.7
South Carolina Electric & Gas	BBB+/A-	8.2	4.2	15.4

Company Name	S&P Corporate Credit Rating	Rate of Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Indeterminate (continued)				
Tampa Electric	BBB-/BBB	10.0	4.7	25.0
Western Massachusetts Electric	BBB	6.1	4.7	11.6
Average	**BBB/BBB+**	**8.1**	**4.7**	**18.5**

Source of data: Standard & Poor's Ratings Direct, *Credit Stats: Electric Utilities -- U.S.* August 24, 2011. Group averages of corporate credit ratings computed by PEG Research for the fiscal years 2008-2010. All other averages provided by Standard & Poor's.

back depreciation and amortization expenses. EBITDA (earnings before interest, taxes, depreciation, and amortization) adds back interest and taxes as well as depreciation and amortization.

Table 3 reports averages for each of the metrics for sampled utilities over the 2008-2010 period. There is an indeterminate category for utilities that are not easily categorized as having operated under capex recovery mechanisms throughout this period. I include in the capex cost recovery mechanisms category the retail formula rates used by a few Southern utilities, since these effectively provide expedited treatment of capex costs.

Caution must be taken in making comparisons in as much as these metrics may differ between the sampled utilities due to differences in several other business conditions as well as due to differences in the use of expedited capex cost recovery. The other relevant business conditions include the ability to rate base CWIP, the local severity of the recent recession, and whether or not utilities operated under forward test years, multi-year rate plans, or some kind of revenue decoupling. Despite these complications, the samples may be large and diverse enough to shed some light on the effect that capex recovery mechanisms have on credit metrics.

56. Q: <u>Please discuss the results of this research.</u>

A: Comparing the results for electric utilities, it can be seen that the values of all four credit metrics were typically more favorable for utilities that had capex recovery mechanisms than for those that did not.

- The capex recovery mechanism utilities had a typical credit rating of BBB+ whereas those that did not had a typical credit rating of BBB.
- The capex recovery mechanism utilities had an average rate of return on capital of 8.6% whereas those that did not had an average return of 7.7%.
- The capex recovery mechanism utilities had an average EBITDA/interest coverage of 5.1 whereas those that did not had an average coverage of 4.3.
- The capex recovery mechanism utilities had an average FFO/debt ratio of 21.9 whereas those that did not had an average ratio of 20.0.

57. Q: <u>What are the precedents for expedited capex cost recovery?</u>

A: Recent precedents for expedited capex recovery mechanisms for electric and gas utilities are summarized in Figure 6. It can be seen that there are precedents in numerous states, including the neighboring states of Pennsylvania and New Jersey. Those for power distribution capex most commonly recover the cost of AMI or more general accelerated modernization programs that improve reliability.

Figure 6 also shows that many gas distributors have capex cost recovery mechanisms. Gas distribution systems in some areas of the country are considerably older than their electric counterparts. The older facilities were often built with cast iron and/or bare steel, materials which today entail high maintenance costs and raise safety concerns. Expedited capex cost recovery helps gas distributors accelerate the replacement of these old facilities. The phenomenon is especially common in the Northeast and East Central states.

Figure 6: Recent Capex Cost Recovery Precedents for US Energy Utilities

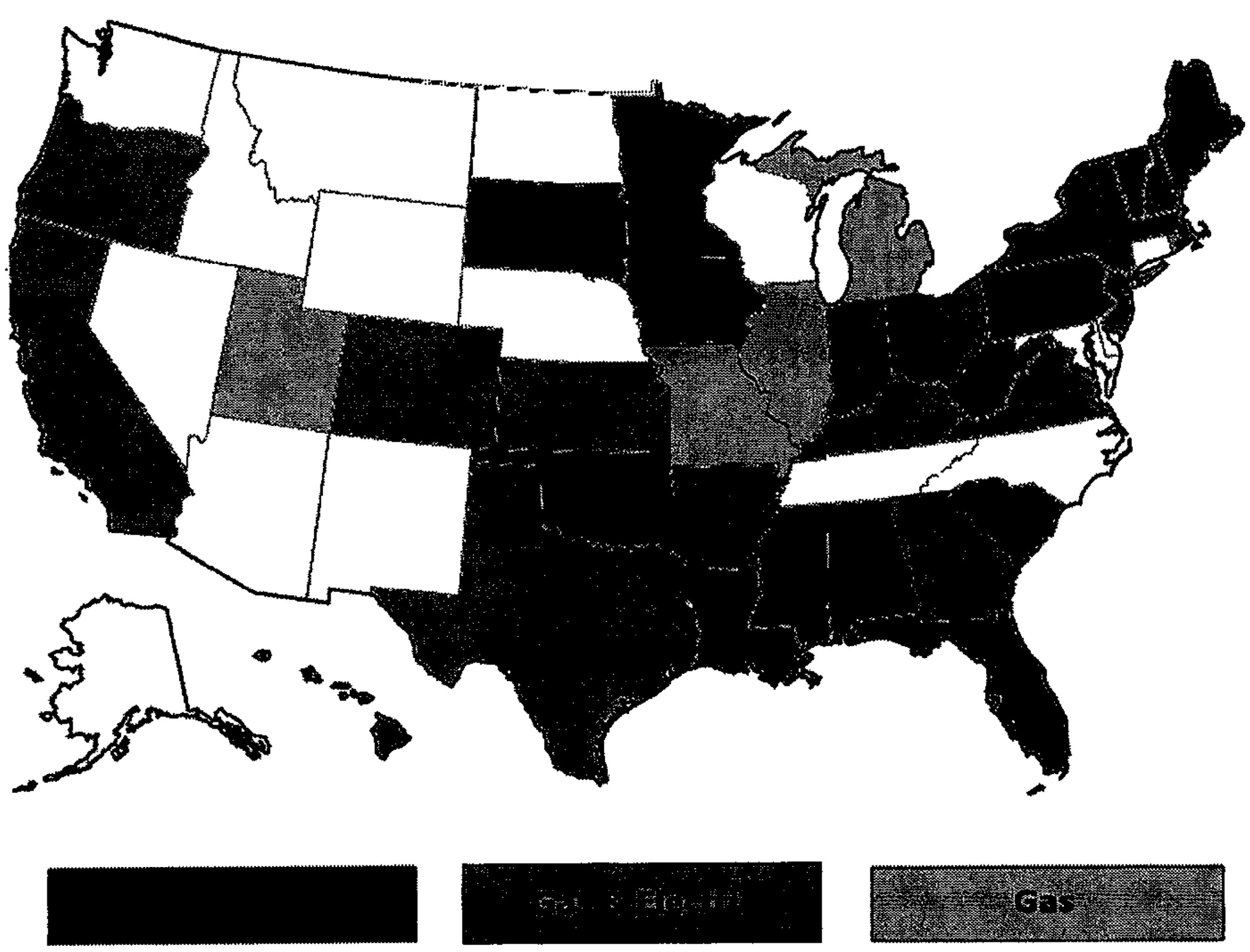
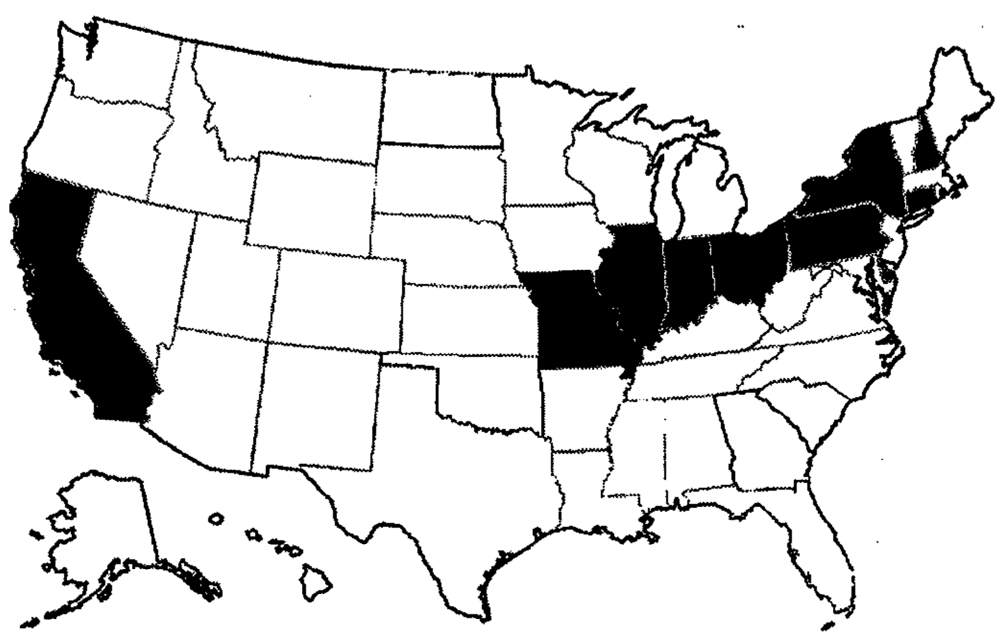


Figure 7 shows that contemporaneous capex cost recovery is also common in the water utility industry. Northeastern and East Central states are once again national leaders. In Delaware, Distribution System Improvement Charges ("DSICs") have been approved for several water utilities under the authority of Chapter 138 of the Delaware Code. I believe that these gas and water utility precedents are quite relevant to the consideration of Delmarva's proposal.

Figure 7: Recent Capex Cost Recovery Precedents for US Water Utilities



58. Q: <u>Why might regulators choose expedited capex cost recovery over alternative remedies for chronic attrition?</u>

A: Decoupling true-up plans and fixed-variable pricing can substantially reduce chronic attrition only for utilities experiencing a substantial decline in average use. This is not the situation of most electric utilities today. As for the other popular remedies, forward test years and multi-year rate plans can involve more sweeping changes in the regulatory system. Moreover, frequent rate cases are still needed with FTYs in a period of enhanced distribution system modernization. Contemporaneous capex cost recovery can surgically address the special challenge posed by sustained high capex and reduce rate case frequency without sweeping changes. For example, any forecast of future capex cost recovered through the mechanism can be subject to future reconciliation. There is no need to forecast other capital costs or future O&M expenses.

59. Q: <u>Isn't expedited capex cost recovery a non-comprehensive approach to ratemaking?</u>

A: Yes, but in an era when traditional regulation can produce chronic underearning and encourage frequent rate cases, many commissions today find non-comprehensive remedies preferable to the salient comprehensive remedies. In addition to expedited capex cost recovery, decoupling is a non-comprehensive remedy, and is clearly popular in many states.

Non-comprehensive remedies have traditionally triggered concerns about overearning, but I have shown that the strength of this concern is an artifact of historical operating conditions that differ from those facing contemporary energy distributors. Overearning from expedited capex cost recovery is much less of a concern in an environment where cost growth is clearly outpacing revenue growth, as I have shown to be the case for distributors engaged in accelerated modernization. Earnings can, in any event, be closely monitored if overearning is a particular concern.

60. Q: <u>Please describe the Reliability Investment Recovery Mechanism that you helped the Company to design.</u>

A: The RIM is an expedited cost recovery mechanism that would target Delmarva's reliability-related capex costs. The investments subject to cost recovery through the RIM would replace aging distribution facilities and/or improve reliability in Delaware. The capex addressed by the RIM would occur after the test year and is not included in the rate base the Company is proposing in another part of this proceeding. For example, it would not include the cost of AMI. Costs of new connections are also excluded and none of the investments would generate new revenue automatically.

Filings would be made annually which forecast, with month to month itemization, the accumulating annual cost of RIM investments in the upcoming year and make certain adjustments for the operation of the RIM in prior years. The cost would be recovered via a rate rider, as discussed in the testimony of Company Witness Santacecilia.

61. Q: <u>How would RIM-related costs be treated in future rate cases?</u>

A: In the Company's next general rate case following implementation of the RIM, the un-depreciated balance of the capex, constituting the great bulk of the total, would be considered for inclusion in the rate base. RIM charges related to costs that are included in the rate base at that time would be terminated.

62. Q: <u>Please describe in more detail the calculation of the RIM revenue requirement.</u>

A: One component of the revenue requirement would be a return on investment. The eligible investment would include appropriate capitalized expenses and the CWIP on facilities that are not yet used and useful. The revenue requirement would also include depreciation on plant that is used and useful and an adjustment for changes in taxes that result from the capex. The calculations would use the Commission-approved depreciation rates and weighted average cost of capital. An illustrative calculation of the revenue requirement and RIM charge is provided in the Direct Testimony of Company Witness Santacecilia. This schedule details the calculation of monthly revenue requirements and an annual charge for the RIM over a 12-month period.

63. Q: <u>What adjustments would be made in the annual filing?</u>

A: The annual RIM filing would, additionally, adjust the revenue requirement for variances between last year's actual costs and RIM revenues. Thus, customers would only pay the costs that Delmarva actually incurs. Any differences would be added to the RIM tariff or, in the case of underspends, returned to ratepayers through that tariff. In calculating the monthly interest on net over- and under-recoveries, the interest rate would be based upon the Company's interest rate obtained on its commercial paper and/or bank credit lines. If both commercial paper and bank credit lines have been used, the weighted average of both sources of debt would be used.

64. Q: <u>What precautions would be taken against a RIM miscalculation?</u>

A: The Company would conduct an internal audit of the RIM each year and report its outcome in the annual hearings. This audit would include a determination of whether the costs recovered through the RIM were recovered, redundantly, through other approved tariffs; whether the surcharges were properly billed to customers in the correct time periods; and whether the costs and revenues were properly identified and recorded. Any errors discovered would be factored into the new RIM tariff with interest. The Sarbanes-Oxley Act provides further protections against RIM miscalculations.

65. Q: <u>What protections exist against overearning under the proposed RIM?</u>

A: Chronic overearning is in my view unlikely under the plan. Delmarva has been underearning for many years, as described in Company Witness Von Steuben's testimony and capex will be higher prospectively, increasing expected attrition. The Company will, in any event, continue to file quarterly earnings statements.

66. Q: <u>Would approval of the RIM completely eliminate the need for base rate cases in the next few years?</u>

A: No. The RIM would address an emerging source of chronic attrition, but would not address all the sources of the Company's underearning. There would still be a need for occasional base rate cases.

67. Q: <u>Would the RIM have an expiration date?</u>

A: A fixed expiration date is not proposed. However, the Commission can initiate a special proceeding to review the RIM at any time. The extension, modification, or termination of the RIM can be considered in such a proceeding.

68. Q: <u>Please explain how the RIM maintains strong incentives for capex containment.</u>

A: Delmarva will file in this proceeding extensive information on its proposed RIM expenditures over a multi-year period. The filing will include data on specific projects and their estimated costs and completion dates. This proceeding should provide sufficient time for the Commission to consider and comment on the general need for increased reliability capex. Parties to the proceeding can potentially agree on a multi-year capex budget and other details of the investment plan in a settlement.

The proceedings to consider annual RIM filings would have a two month window for the parties to exchange information on the plan for the coming year and come to agreement on a set of projects and costs. A full and thorough final review of whether RIM costs are reasonable would occur in the rate case. This review would include consideration of whether the investments are used and useful. The rates to recover the costs of RIM-eligible investments would be interim rates, and RIM revenues associated with any future cost disallowances would be subject to true-up with interest in the rate case.

It should also be remembered that, in a period of substantial capex, it will remain a challenge for Delmarva to manage its business in a way that allows it to earn close to its authorized ROE. Consider, finally, that the Company will likely hope for the RIM to continue. This gives Delmarva an incentive to keep the operation of the RIM non-controversial. For example, the Company will wish to avoid any appearance of overspending.

69. Q: <u>Does expedited capex cost recovery make sense for Delmarva's infrastructure investment plan?</u>

A: Yes. Expedited capex cost recovery would surgically address the principal source of financial attrition that Delmarva is likely to face in the next several years. With more investment, reliability would improve. Higher capital market costs would be avoided, and streamlined regulation would reduce regulatory cost and encourage better operating performance. Salient alternatives, like frequent rate cases and multi-year rate plans, may involve regulatory reforms that are more sweeping than what the Commission prefers. Expedited capex cost recovery for RIM projects would permit Delmarva and other parties to regulation in Delmarva to focus on the challenge of improving system reliability cost effectively.

70. Q: **<u>You have also proposed that the Commission allow the use of forward test years prospectively. Is there merit in combining this with a capex tracker?</u>**

A: Yes. I have already noted that the addition of a forward test year to Delmarva's current regulatory system will likely solve the Company's regulatory lag problem only with frequent rate cases. With a RIM in place, however, a forward test year can materially help reduce the frequency of rate cases during the period of accelerated system modernization and beyond. The resultant benefits would more than make up for the somewhat greater complexity of individual rate cases. In summary, capex recovery mechanisms and forward test years are complementary measures for capturing the full benefits of regulatory lag mitigation.

71. Q: **<u>Are there other regulatory lag mechanisms available to the Commission for consideration in this proceeding?</u>**

A: Yes, multi-year rate plans are the most common approach to the regulation of energy distributors in the advanced industrial world. As I mentioned earlier in my testimony, I believe this to be the best approach to energy distributor regulation and that its use will spread steadily in the United States, as it has in

Canada and many other countries. A multi-year rate plan could be combined with a RIM, using the multi-year rate plan for conventional costs and the RIM for expedited recovery of the cost of incremental reliability investments. This would be especially easy to do with a hybrid or stairstep revenue cap. The multi-year rate plan would then recover the base capex budget. This approach reduces the need to establish an accurate multi-year capex budget in this proceeding. Revenues from incremental capex can be reconciled with the actual capex costs annually. Compared to the RIM-only approach, it would provide Delmarva with more effective relief from chronic attrition. Rate cases would be held less frequently, and this would encourage better utility management by strengthening incentives for cost performance and affording senior managers more time to focus on the basic business.

72. Q: <u>Please summarize the regulatory reforms that you advocate for Delmarva.</u>

A: I recommend that the Commission adopt a reliability investment recovery mechanism ("RIM") and sanction the use of fully forecasted test years in Delmarva's upcoming rate cases. The Commission may also want to consider some form of a multi-year rate plan in conjunction with the RIM.

73. Q: <u>Does this conclude your testimony?</u>

A: Yes it does.

RESUME OF
MARK NEWTON LOWRY

November 2011

Home Address:	1511 Sumac Drive Madison, WI 53705 (608) 233-4822	Business Address:	22 E. Mifflin St., Suite 302 Madison, WI 53703 (608) 257-1522 Ext. 23

Date of Birth: August 7, 1952

Education: High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Agricultural and Resource Economics, University of Wisconsin -Madison, May 1984

Relevant Work Experience, Primary Positions:

Present Position — President, Pacific Economics Group Research LLC, Madison WI

Chief executive of the research unit of the Pacific Economics Group consortium. Leads internationally recognized practice in alternative regulation ("Altreg") and utility statistical research. Other research specialties include: codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include senior management, supervision of research, and expert witness testimony.

October 1998-February 2009 — Partner, Pacific Economics Group LLC, Madison, WI

Managed PEG's Madison office. Specific duties include project management and research, written reports, public presentations, expert witness testimony, personnel management, and marketing.

January 1993-October 1998 — Vice President
January 1989-December 1992 — Senior Economist, Christensen Associates, Madison, WI

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility PBR and statistical benchmarking during these years.

Aug. 1984-Dec. 1988 — Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Teaching and research specialty: analysis of markets for energy products and metals.

August 1983-July 1984 — Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 — Research Assistant, Department of Agricultural and Resource Economics, University of Wisconsin-Madison

Dissertation research under Dr. Peter Helmberger on the role of speculative storage in markets for field crops. Work included the development of an econometric rational expectations model of the U.S. soybean market.

March 1981-March 1982 — Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States.
- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 — Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.

Research on the behavior of inventories in non-competitive metal markets.

Major Consulting Projects:

1. Research on Gas Market Competition for a Western Electric Utility. 1981.
2. Research on the Natural Gas Policy Act for a Northeast Trade Association. 1981
3. Interruptible Service Research for an Industry Research Institute. 1989.
4. Research on Load Relief from Interruptible Services for a Northeast Electric Utility. 1989.
5. Design of Time-of-Use Rates for a Midwest Electric Utility. 1989.
6. PBR Consultation for a Southeast Gas Transmission Company. 1989.
7. Gas Transmission Productivity Research for a U.S. Trade Association. 1990.
8. Productivity Research for a Northeast Gas and Electric Utility. 1990-91.
9. Comprehensive Performance Indexes for a Northeast Gas and Electric Utility. 1990-1991.
10. PBR Consultation for a Southeast Electric Utility. 1991.
11. Research on Electric Revenue Adjustment Mechanisms for a Northeast Electric Utility. 1991.
12. Productivity Research for a Western Gas Distributor. 1991.
13. Cost Performance Indexes for a Northeast U.S. Gas and Electric Utility. 1991.
14. Gas Transmission Rate Design for a Western U.S. Electric Utility. 1991.
15. Gas Supply Cost Indexing for a Western U.S. Gas Distributor. 1992.
16. Gas Transmission Strategy for a Western Electric Utility. 1992.
17. Design and Negotiation of Comprehensive Benchmark Incentive Plans for a Northeast Gas and Electric Utility. 1992.

18. Gas Supply Cost Benchmarking and Testimony for a Northeast U.S. Gas Distributor, 1992.
19. Bundled Power Service Productivity Research for a Western Electric Utility. 1993-96.
20. Development of PBR Options for a Western Electric Utility. 1993.
21. Review of the Regional Gas Transmission Market for a Western Electric Utility. 1993.
22. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1993.
23. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1994.
24. Productivity Research for a Western Gas Distributor. 1994.
25. White Paper on Price Cap Regulation for a U.S. Trade Association. 1994.
26. Bundled Power Service Benchmarking for a Western Electric Utility. 1994.
27. White Paper on PBR for a U.S. Trade Association. 1995.
28. Productivity Research and PBR Plan Design for a Northeast Gas and Electric Company. 1995.
29. Regulatory Strategy for a Restructuring Canadian Electric Utility. 1995.
30. PBR Consultation for a Japanese Electric Utility. 1995.
31. Regulatory Strategy for a Restructuring Northeast Electric Utility. 1995.
32. Productivity Research and Plan Design Testimony for a Western Gas Distributor. 1995.
33. Productivity Testimony for a Northeast Gas Distributor. 1995.
34. Speech on PBR for a Western Electric Utility. 1995.
35. Development of a PBR Plan for a Midwest Gas Distributor. 1996.
36. Stranded Cost Recovery and Power Distribution PBR for a Northeast Electric Utility. 1996.
37. Benchmarking and Productivity Research and Testimony for a Northeast Gas Distributor. 1996.
38. Consultation on Gas Production, Transmission, and Distribution PBR for a Latin American Regulator. 1996.
39. Power Distribution Benchmarking for a Northeast Electric Utility. 1996.
40. Testimony on PBR for a Northeast Power Distributor. 1996.
41. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
42. Design of Gas Distributor Service Territories for a Latin American Regulator. 1996.
43. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
44. Service Quality PBR for a Canadian Gas Distributor. 1996.
45. Productivity and PBR Research and Testimony for a Canadian Gas Distributor. 1997.
46. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1997.
47. Design of a Price Cap Plan for a South American Regulator. 1997.
48. White Paper on Utility Brand Name Policy for a U.S. Trade Association. 1997.
49. Bundled Power Service Benchmarking and Testimony for a Western Electric Utility. 1997.
50. Review of a Power Purchase Contract Dispute for a Midwest City. 1997.
51. Research on Benchmarking and Stranded Cost Recovery for a U.S. Trade Association. 1997.
52. Research and Testimony on Productivity Trends for a Northeast Gas Distributor. 1997.
53. PBR Plan Design, Benchmarking, and Testimony for a Southeast Gas Distributor. 1997.
54. White Paper on Power Distribution PBR for a U.S. Trade Association. 1997-99.
55. White Paper and Public Appearances on PBR Options for Australian Power Distributors. 1997-98.
56. Gas and Power Distribution PBR Research and Testimony for a Western Energy Utility. 1997-98.
57. Research on the Cost Structure of Power Distribution for a U.S. Trade Association. 1998.
58. Research on Cross-Subsidization for a U.S. Trade Association. 1998.
64. Testimony on Brand Names for a U.S. Trade Association. 1998.
65. Research and Testimony on Economies of Scale in Power Supply for a Western Electric Utility. 1998.
66. PBR Plan Design and Testimony for a Western Electric Utility. 1998-99.
67. PBR and Bundled Power Service Testimony and Testimony for Two Southeast U.S. Electric Utilities. 1998-99.
68. Statistical Benchmarking for an Australian Power Distributor. 1998-9.

69. Testimony on Functional Separation of Power Generation and Delivery for a U.S. Trade Association. 1998.
70. Design of a Stranded Benefit Passthrough Mechanism for a Restructuring Electric Utility. 1998.
71. Consultation on PBR and Code of Conduct Issues for a Western Electric Utility. 1999.
72. PBR and Bundled Power Service Benchmarking Research and Testimony for a Southwest Electric Utility. 1999.
73. Power Transmission and Distribution Cost Benchmarking for a Western Electric Utility. 1999.
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76. Benchmarking Research for an Australian Power Distributor. 2000.
77. Critique of a Commission-Sponsored Benchmarking Study for Three Australian Power Distributors. 2000.
78. Statistical Benchmarking for an Australian Power Transco. 2000.
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80. PBR Workshop (for Regulators) for a Northeast Gas and Electric Utility. 2000.
81. Research on Economies of Scale and Scope for an Australian Electric Utility. 2000.
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90. TFP and Other PBR Research and Testimony for a Northeast Power Distributor. 2000.
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100. PBR Research for a Canadian Gas Distributor. 2003.
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111. White Paper on Unbundled Storage and Local Gas Markets for a Midwestern Gas Distributor. 2004.
112. Statistical Benchmarking Research for a British Power Distributor. 2004.
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121. Statistical Benchmarking of a Nuclear Power Plant and Testimony. 2005.
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FORWARD TEST YEARS FOR US ELECTRIC UTILITIES

Prepared for

Edison Electric Institute

Prepared by

Mark Newton Lowry, PhD
President

David Hovde, MS
Vice President

Lullit Getachew, PhD
Senior Economist

Matt Makos
Consultant

PACIFIC ECONOMICS GROUP RESEARCH LLC
22 East Mifflin St., Suite 302
Madison, Wisconsin USA 53703
608.257.1522

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EXECUTIVE SUMMARY

U.S. investor-owned electric utilities (electric "IOUs") in jurisdictions with historical test year rate cases are grappling today with financial stresses that threaten their ability to serve the public well. Unit costs are rising because growth in sales volumes and other billing determinants is not keeping pace with growth in cost. Cost growth is stimulated by the need to rebuild and expand legacy infrastructure and to meet environmental and other public policy goals. In this situation historical test years, still used in almost 20 U.S. jurisdictions, can erode credit quality and condemn IOUs to chronic underearning.

This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future.

CHAPTER 1 (FORWARD TEST YEARS) provides an introduction to test year issues. Problems with historical test years are discussed. We explain that the "matching principle" used to rationalize historical test years assumes that cost and revenue remain balanced. This assumption doesn't hold when unit cost is rising. In a rising unit cost environment, rates based on historical test years are uncompensatory even in the year they are implemented. As a result, operating risk increases, raising the cost of obtaining funds in capital markets. Service quality may be compromised. Customers receive out of date price signals that encourage excessive consumption. The problems are aggravated when rate hearings are protracted. Utilities commonly respond with more frequent rate case filings but these raise regulatory cost, weaken performance incentives, and distract managers from their basic business while still not giving utilities sufficient attrition relief. It is unfair to expect utilities to offset revenue shortfalls produced by regulatory lag with higher productivity and unrealistic to think that they can do so. Forward test years can yield better results for utilities and their customers.

The unit cost trends of utilities are driven by conditions that are substantially beyond their control. These conditions include trends in input prices, productivity, and the average use of utility services by customers. For the matching principle to work, some combination of growth in utility productivity and average use must offset input price inflation.

Utility efforts to promote customer energy conservation slow growth in average use, thereby raising unit cost and making historical test year rates less compensatory. Forward test years can anticipate the slower growth in average use that results from utility conservation programs. They therefore help to remove utility disincentives to promote conservation aggressively.

The forecasts of costs and billing determinants that are made in a forward test year proceeding are uncertain but involve conditions that are at most two years into the future. A large part of utility cost is no more difficult to budget under forward test years than under historical test years. More volatile components of cost are often subject to true-up mechanisms. Conservative, well-reasoned methods for making forecasts are available. In a rising unit cost environment, the uncertainty of forecasts is less of a concern than the bias of historical test year rates.

Utilities seeking forward test years must be mindful of their high evidentiary burden. The following rate case measures bolster confidence.

- Provide concrete evidence as to why future test years and not historical test years are needed under current circumstances. Evidence concerning trends in the unit cost of utilities and in key unit cost drivers is especially pertinent.
- Provide cost and billing determinant data for one or more historical reference years and carefully explain methodologies for predicting cost and billing determinant changes between those years and the forward test year.
- Use forecasting methods that are transparent and based on reason but not needlessly complex.
- Routine variance reports comparing costs and billing determinants to utility forecasts can increase comfort that forecasts are unbiased.

CHAPTER 2 (TEST YEAR HISTORY) presents a brief history of test years in the United States. Historical test years became the norm in the U.S. because periods of stable or declining unit cost, made possible by slow price inflation and brisk growth in utility productivity and average use, were the rule rather than the exception in the electric utility industry prior to the late 1960s. Growth in productivity and average use have slowed enough in subsequent decades that unit cost has frequently risen. Under favorable business conditions, unit cost can still be flat for several years, making historical test years more reasonable. However, conditions like these can give way to conditions in which unit cost rises for years at a time.

Forward test years were adopted in many jurisdictions during the 1970s and 1980s as unit cost grew briskly, spurred by input price inflation and slower growth in average use and utility productivity. Unit cost growth was flat during most of the 1990s because business conditions driving unit cost growth were more favorable. Input price inflation slowed. Investment needs were more limited, as many utilities grew into capacity added during the construction cycle of the 1970's and early 1980's. Average use grew less rapidly than in the past but nonetheless increased appreciably in most years. Under these conditions, utilities were sometimes able to commit to multiyear base rate freezes.

Unit cost growth has since rebounded due to higher inflation, increased plant additions, and slowing growth in average use. Commissions in several states with historical test year traditions have recently moved in the direction of forward test years. Many of these states are in the West, where comparatively rapid economic growth has stimulated plant additions. The ranks of U.S. jurisdictions that use alternatives to historical test years have swollen and now encompass well over half of the total.

In summary, historical test years became the norm in U.S. rate cases during decades when unit cost was flat or declining due to remarkably brisk utility productivity and average use. Under contemporary conditions, in which average use grows slowly, if at all, and the productivity growth of utilities is more like that of the economy, unit cost may rise for extended periods undermining the matching principle.

CHAPTER 3 (EMPIRICAL SUPPORT FOR FORWARD TEST YEARS) presents results of some empirical research on test year issues. In original work for this paper, we calculated the unit cost trends of a sample of vertically integrated electric utilities from 1996 to 2008. Trends in business conditions that drive unit cost growth were measured. We also considered how test year policies affect credit metrics and utility operating performance.

Here are some salient results.

- The unit cost of sampled utilities was fairly stable from 1996 to 2002 but has since rebounded, averaging 2.3% annual growth from 2003 to 2008. The underlying causes of rising unit cost included higher input price inflation and capital spending and slower growth in the average system use of residential and commercial customers.
- In the three year period from 2006 to 2008 average use actually declined for the typical utility, pulled down by sluggish economic growth and government policies that encourage conservation. The decline was especially marked in states with large conservation programs.
- These results suggest that many IOUs may not be able in the future to count on brisk growth in average use by residential and commercial customers to buffer the impact on unit cost growth of input price inflation and increased plant additions. The problem will be considerably more acute in service territories where there are aggressive conservation programs.
- Utilities operating under forward test years were more profitable and had better credit ratings on average than those of utilities operating under historical test years. For example, from 2006 to 2008 utilities operating under forward test years realized an average return on capital of 9.2% and maintained a typical credit rating between A- and BBB+ whereas the utilities operating under historical test years realized an average return of 7.9% and maintained a typical credit rating between BBB and BBB-.
- Examination of recent trends in operation and maintenance ("O&M") expenses of utilities provides no evidence that historical test years encourage better cost management.

CHAPTER 4 (CONCLUDING REMARKS) provides some suggestions as to how interested regulators can get started down the road to forward test years.

1. Allow a forward test year on a trial basis for one interested utility.

2. Allow forward test years on an as needed basis when a utility makes a convincing case that rising unit costs make historical test years unjust and unreasonable.
3. Borrow one or two of the methods used in FTY rate cases to make additional adjustments to *historical* test year costs and billing determinants. For example, historical test year O&M expenses can be adjusted for forecasts of price inflation prepared by respected independent agencies. Special adjustments can be made for large plant additions that are expected to be finished in the near future.
4. Try a current test year (essentially the year of the rate case), which involves forecasts only one year into the future. Current test years can be combined with interim rate increases which are subject to true up when the rate case is finalized. A combination of a current test year and interim rates eliminates regulatory lag without the necessity of a two year forecast.

In states where regulators aren't ready to abandon historical test years but are sympathetic to the attrition problems caused by rising unit costs, alternative measures are available to relieve the financial attrition. Options include the following:

1. Make sure that historical test year calculations incorporate the full array of normalization, annualization, and known and measurable change adjustments that are used in other jurisdictions.
2. Grant utilities interim rate increases at the outset of a rate case. Even when later adjusted for the final rate case outcome, interim rates effectively reduce regulatory lag by a year.
3. Capital spending trackers can ensure timely recovery of the costs of plant additions, without rate cases, as assets become used and useful.
4. Several methods have been established to compensate utilities for acceleration in unit cost growth that results from flat or declining average system use. These include decoupling true up plans, lost revenue adjustment mechanisms, and higher customer charges.
5. Multiyear rate plans can give utilities rate escalation between rate cases for inflation and other business conditions that drive cost growth.

1. FORWARD TEST YEARS

This chapter provides an in depth discussion of test year issues. Basic test year concepts are introduced in Section 1.1. The rationale for forward test years is discussed in Section 1.2. The kinds of evidence used in forward test year proceedings are explored in Section 1.3.

1.1 Basic Concepts

1.1.1 Rate Cases

In the United States, rates for the services of energy utilities are periodically reset by regulators in litigated proceedings called rate cases. These cases typically take about nine or ten months to resolve and sometimes end in a settlement between contending parties which is approved by the regulator. The first year following approval of new rates is called the "rate year".

In a rate case, rates are reset to reflect the cost and service levels of the utility in a test year. The first step in this process is to establish a revenue "requirement" that is commensurate with a cost for service deemed reasonable for test year operating conditions. Rates are then established which recover the revenue requirement given the levels of service provided in the test year. The service levels (*e.g.* the number of customers served and the power delivery volume) are sometimes called "billing determinants".

Bills of energy utilities often contain charges to recover the cost of energy commodities (*e.g.* fuel and purchased power) procured on a customer's behalf which are separate from the charges to recover the cost of capital, labor, and other inputs used to operate their systems. The rates that recover the costs of non-energy inputs are commonly called "base" rates. Base rate revenues are sometimes called "margins".

Rates for the cost of energy procurement are commonly subject to true ups to recover the actual cost of energy procured. Base rates, on the other hand, have traditionally been reset only in rate cases. The earnings of utilities thus depend primarily on the difference between their base rate revenues and the cost of their base rate inputs.

1.1.2 Historical Test Years

Various kinds of test years are used in rate cases today. An historical test year ("HTY") is a twelve month period that ends before the rate case filing. It typically ends a few months before the filing because it is desirable for the test year to be as current as possible but it takes several months to properly account for a year of costs and take the other steps needed to prepare a rate case. The year between an historical test year and the rate year is sometimes called the "bridge year".

The passage of time between a test year and the rate year is sometimes called "regulatory lag".[1] The lag between an historical test year and the rate year is typically two years. A utility filing for new rates in calendar 2011, for example, would typically file in March or April of 2010 using a calendar 2009 test year. Thus, historical test year rates applicable in 2011 would typically reflect business conditions in 2009.

Regulatory lag in this case has several causes. One is the necessity of using a year of historical data in the rate case filing. Another is the time required to prepare a rate case filing. Still another is the time required to execute the rate case and reach a final decision on new rates.

Historical test year data are usually adjusted in some fashion to make rates more relevant to rate year business conditions. Costs and billing determinants are often normalized for the effects of volatile business conditions on the grounds that there is no reason to expect these conditions to be abnormal during the rate year. For example, if residential and commercial delivery volumes during an historical test year were elevated by unusually high summer temperatures, they may be statistically normalized to reflect average summer weather conditions. Other examples of abnormal events that can prompt normalization adjustments include ice storms, recessions, and extended generation plant outages.

Cost and output conditions in the historical test year may also be "annualized". Effects may be removed, for a full year, of conditions that occurred during part of the HTY but are not expected to continue. One example would be costs reported for the HTY that pertained to years before the test year. Another would be the volume and peak demand of a large industrial customer who has closed its local operations.

Impacts of conditions that occurred only during certain months of the test year and are expected to prevail in the near future may also be annualized. For example, the value of the rate base at the end of an historical test year is sometimes assumed to be applicable for

[1] This is one of several definitions of "regulatory lag" which are sometimes used in discussions of regulation. Another is the length of time between rate cases.

the entire year for purposes of calculating depreciation and the return on rate base. If union wage rates are raised in the last month of the HTY pursuant to the terms of a labor contract, labor expenses may be adjusted so that the higher cost per employee is effective for the entire year.

Cost and output data may, additionally, be adjusted for "known and measurable" (sometimes called "imminent certain") changes that have already occurred since the historical test year or are likely to occur in the near future. For example, if a labor contract provides for an escalation in union wages in the bridge year, HTY cost may be adjusted to reflect the wage rates provided in the contract.

The adjustments made to HTY cost and billing determinants vary across jurisdictions. While all such adjustments tend to make rates more relevant to rate year conditions, the HTY adjustment process often ignores important changes in business conditions that occur between an historical test year and a rate year. Here are some typical omissions.

- Cost is usually not adjusted to reflect future inflation in the prices of materials, services, and new equipment because the extent of such inflation isn't known with certainty.
- Costs of plant additions in the bridge year and the rate year are often omitted if their completion date and/or final cost aren't known with certainty.
- Billing determinants are usually not adjusted to reflect trends that are likely to occur after the test year because these are not known with certainty.
- Adjustments for known and measurable changes are sometimes limited arbitrarily to the bridge year.

1.1.3 Forward and Hybrid Test Years

A forward or future test year ("FTY") is a twelve month period that begins after the rate case is filed. Test year cost and billing determinants must in this case be forecasted, and forward test years are for this reason sometimes called forecasted test years. Utilities in some jurisdictions file rate cases with *multiple* forward test years. In the Canadian province of Alberta, for instance, it has recently been common for utilities to file for two forward test years in a rate case.

Most commonly, a forward test year begins about the time that the rate case is expected to end. The test year is then the same as the rate year. A utility filing on April 1

2010, for instance, might use calendar 2011 as its test year on the assumption that the rate case will take nine months to complete.

Some utilities use FTYs that begin about the time of the rate case filing. This kind of test year may be called a "current" FTY. The initial filing is in this case based entirely on forecasts but some months of actual data for the test year become available in the course of the proceeding.

Utilities in some states make rate case filings using test years that encompass some months *before* the filing and some months *afterwards*. Data for all months of the test year are then likely to become available during the course of the filing. This kind of test year has been called a "hybrid" or "partial" test year.

1.2 Rationale for Forward Test Years

1.2.1 The Financial Challenge

The Key Role of Unit Cost

We have noted that the rates that result from a rate case are designed to recover a revenue requirement that equals cost in a test year. In the case of an historical test year the new rates embody business conditions that are typically about two years older than those of the rate year. Business conditions are likely to change between an historical test year and the rate year, causing both cost and revenue to differ from the HTY level. For rates to be exactly compensatory, base rate cost and revenue must differ from their HTY levels in the same proportion.

The assumption that cost and revenue remain in balance underlies the matching principle that regulators still use to rationalize historical test years. Kamershen and Paul note in a thoughtful 1978 article on regulatory lag that "Philosophically, the strict [historical] test year assumes the past relationship among revenues, costs, and net investment will continue into the future."[2] A 2003 NARUC *Rate Case and Audit Manual* states in this regard that

> When looking at an historical test year, one of the first questions asked is whether the test year is too stale to make it a reasonable basis upon which to establish rates for a future period… In looking at the months beyond the end of the test year, have the growth rates for rate base, expenses, and revenues all remained fairly close and constant, maintaining the test year relationship

[2] David R. Kamershen and Chris W. Paul II, "Erosion and Attrition: A Public Utility's Dilemma", *Public Utilities Fortnightly*, December 1978, p. 23.

> among these three elements, or has one element changed dramatically, making the test year out of kilter with current operations? If so, can this situation be resolved through adjustments to the test year?[3]

Cost in the rate year is likely to be substantially higher than cost in an historical test year. To understand why, consider that cost growth in any business can be decomposed into inflation in the prices it pays for inputs plus the growth in its output less the growth in its productivity:

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Output} - \textit{growth Productivity}. \qquad [1]$$

The productivity growth of a business is typically not rapid enough to offset the combined effects of input price inflation and output growth. A recent study reported in testimony by Pacific Economics Group ("PEG") found, for example, that a national sample of U.S. power distributors averaged 1.03% annual growth in multifactor productivity ("MFP") from 1996 to 2006 whereas input price growth averaged 2.72% and customer growth averaged 1.00%.[4] The productivity trend of sampled distributors was similar to that of the U.S. private business sector but far from sufficient to offset the combined effects on cost of input price inflation and customer growth.

As for base rate revenue during the rate year, it can exceed the HTY revenue requirement only due to growth in billing determinants because rates are fixed at levels that reflect HTY conditions. Whether or not historical test year rates are compensatory thus depends critically on whether *unit* cost is stable in the sense that growth in billing determinants has kept pace with cost growth. If cost growth exceeds growth in billing determinants, unit cost will rise and HTY rates will be uncompensatory.

An element of complexity is added when it is considered that a utility offers many services and gathers revenue for each service from multiple charges, each with its own billing determinant. A bill for residential service, for instance, typically involves a flat monthly charge called a "customer" or "basic" charge and a "volumetric" (per kWh) charge. In this world of multiple billing determinants, historical test years will yield uncompensatory rates to the extent that cost growth between the test year and the rate year exceeds a *weighted average* of the growth in billing determinants, where the weight for each determinant is its

[3] NARUC Staff Subcommittee on Accounting and Finance, *Rate Case and Audit Manual*, Summer 2003.
[4] Mark Newton Lowry, *et al.*, *Revenue Adjustment Mechanisms for Central Vermont Public Service Corporation*, Exhibit CVPS-Rebuttal-MNL-2 in Docket No. 7336, June 2008.

share of the total base rate revenue. In other words, rates are uncompensatory when cost growth exceeds the growth in a billing determinant *index*. This is the definition of growth in a *unit cost index*.

The utility uses most of its base rate revenue to pay its workforce, vendors of materials and services (including construction services), bondholders, and tax authorities. The residual margin, called net income or earnings, is available to provide the company's shareholders with a return on their investments. The return on equity is the component of cost that is most at risk for non-recovery when base rate revenue falls short of cost. When historical test year rates are non-compensatory they can reduce a utility's rate of return on equity ("ROE") materially.

<u>Unit Cost Drivers</u>

If the unit cost growth of a utility has made new historical test year rates non-compensatory, it may fairly be asked whether utility actions could have stopped the growth and avoided the problem. Research over many years has shown that the unit cost of a utility is driven chiefly by changes in business conditions that are beyond its control. Growth in the unit cost of a utility's base rate inputs depends on inflation in the prices it pays for those inputs, growth in the productivity with which it uses the inputs, and an average use effect:

$$\textit{growth Unit Cost} = \textit{growth Input Prices} - (\textit{growth Productivity} + \textit{Average Use}). \qquad [2]$$

We discuss each of these unit cost "drivers" in turn.

Input Price Inflation Inflation routinely occurs in the prices utilities pay for labor, materials, services, and equipment. Since utilities have capital-intensive technologies, inflation in the price of capital is an especially important driver of their input price growth. The trend in the price of capital depends chiefly on trends in construction costs, tax rates, and the going rates of return on debt and equity in capital markets.[5]

Productivity The productivity growth of a utility depends on various conditions that include technological change, the realization of scale economies, and the pace of plant additions as

[5] The impact of construction cost on price inflation is complex. In setting rates, utility plant is valued in historical dollars. The cost of service thus depends on prices paid for construction in past decades. Construction costs in more recent years matter more because the corresponding assets are less depreciated. The rate base will tend, on average, to reflect construction costs more than a decade into the past. For most utilities, new investments therefore embody more than a decade of construction cost inflation compared to investments of average vintage. This is one of the reasons why unusually large plant additions can increase the rate base so substantially.

well as utility efforts to root out inefficiencies. Plant additions may boost efficiency gains in the long run but can slow them in the short run, especially if they involve major investments such as new base load generating units, advanced metering infrastructure, or an accelerated program to replace aging infrastructure. Scale economies depend on the pace of output growth and on whether the utility is so large that it has reached a minimum efficient scale at which incremental scale economies from output growth aren't available.

The ability of utilities to achieve productivity surges is limited in the short run. Since technology is capital intensive, the depreciation and return on rate base associated with older investments --- which cannot be changed in the short run --- account for a large share of the total cost of base rate inputs. A utility can increase productivity only by slowing growth in O&M expenses and plant additions. Opportunities to achieve *sustained* productivity gains often involve sizable upfront costs and net gains may not occur for more than a year. A downsizing of the labor force, for instance, may involve severance payments. The chief means for a utility to trim its cost in the very short run is to defer maintenance expenses and plant additions. Such deferrals must be followed by higher expenses in short order if service quality is to be maintained. A utility can't rely on a deferral strategy year after year when it is filing frequent rate cases.

Average Use A utility's unit cost growth also depends on the difference in the impact that its output growth has on its revenue and its cost. When output growth boosts revenue more than cost, unit cost growth slows. When output growth causes cost to rise more rapidly than revenue, unit cost growth accelerates.

A utility's output growth has different impacts on revenue and cost when two conditions are present. One is that the design of base rates doesn't reflect the drivers of base rate input cost. The other is that billing determinants tend to grow at a different rate than cost drivers.

Consider, first, whether the design of utility base rates is cost causative. The cost of a utility's base rate inputs is largely fixed in the short run with respect to system use. Cost is much more sensitive to growth in the number of customers served.[6] As for billing determinants, we have seen that utility tariffs for most services involve multiple charges. These include one or more "variable" charges that are so called because they vary with

[6] Cost growth may also depend, in the long run, on the growth in peak demand and/or the delivery volume.

system use. Volumetric charges vary with the volume of power delivered. "Demand" charges vary with the peak level of demand (*i.e.* the highest hourly volume registered during the month). There are, additionally, "fixed" charges that are so called because they do not vary with a customer's use of the system during the billing period. Chief amongst the fixed charges of electric utilities are customer charges. Residential and small business customers account for the bulk of a utility's base rate revenue because these customers account for the bulk of a utility's cost. In these customer classes, base rate revenue is drawn chiefly from volumetric charges.

Under these circumstances, the difference between the way that output growth affects revenue and cost is chiefly a matter of the difference between the trends in the volume of sales to residential and small business customers and the trends in the number of customers served. This is equivalent to the trends in the delivery *volume per customer* of these service classes, which are sometimes referred to as the trends in their average (system) use. Unit cost growth slows when average use rises and accelerates when growth in average use slows.

In the electric utility industry, as in most sectors of the economy, the productivity growth of utilities has for decades been a good bit slower than the inflation in the prices they pay for inputs.[7] The recent PEG study noted earlier, for example, found that power distributor productivity growth fell short of input price growth by about 169 basis points annually on average from 1996 to 2006.[8] Under conditions like these, the average use trends of residential and small-volume business customers play an important role in determining whether a utility's unit cost rises. If growth in average use is *brisk* (*e.g.* 1.5 to 2% annually), the difference between input price and cost efficiency growth can be offset.[9] If average use is *static*, unit cost will rise substantially even under normal inflationary conditions. If average use is *declining*, the rise in unit cost can be quite rapid.

Recent changes in state and federal policy are encouraging more electricity demand-side management ("DSM") and development of customer-sited solar resources. These policies include net metering, tighter appliance efficiency standards and building codes, and

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[7] The difference is greater in periods of brisk input price inflation and smaller in periods of slow inflation, since productivity does not characteristically rise and fall with inflation.
[8] Lowry *et al.* (2008) *op. cit.*
[9] Irston Barnes wrote, for example, in a classic treatise on rate regulation, that "as an offset to such factors making for rising rates, the increased volume of business that usually accompanies an upward movement of prices may so reduce the overhead charges per unit as to make any increase in rates unnecessary". See Irston R. Barnes, *The Economics of Public Utility Regulation* (New York: F.S. Crofts, 1942).

subsidies for energy efficiency investments. Our discussion suggests that such programs can accelerate unit cost growth by slowing growth in average use. Whether or not the utility provides DSM programs, average use can become static or decline, removing a key means by which utilities have traditionally coped with input price inflation and avoided unit cost growth. The problem can be remedied by redesigning rates in ways that raise customer charges. But rate designs are regulated and regulators in the United States generally do not sanction high customer charges.[10]

Implications Our analysis suggests that the unit cost of an electric utility is likely to rise, making historical test year rates non-compensatory, to the extent that the following external business conditions prevail.

- Input price inflation is brisk.
- Utilities need to make large plant additions that temporarily slow productivity growth.
- Average use of the utility system is static or declining.

Situations in which unit cost is stable, encouraging use of historical test years, include those in which inflation is slow, utilities aren't making large plant additions, and average use is growing briskly.

A program to accelerate the replacement of aging distribution facilities provides a classic example of the non-compensatory nature of historical test year rates. Suppose that a power distributor replaces 10% of its distribution infrastructure during a year when new rates are implemented. The new plant has capacity similar to the plant replaced but reflects more than forty years of construction cost inflation. The company's rate base will rise substantially, temporarily slowing productivity growth and accelerating unit cost growth. Even with normal growth in input prices and average use a utility with rates based on historical test years may earn little return on this sizable investment for as much as two years after it becomes used and useful.

Conclusions

These results permit us to draw several conclusions concerning the reasonableness of historical test years in ratemaking.

[10] High customer charges are more common for U.S. gas utilities and for gas and electric IOUs in Canada.

1) Historical test years are rationalized by a matching principle that assumes a balance of cost and revenue. Our analysis shows that this relationship is not balanced in a rising unit cost environment.
2) An individual utility reporting that rates produced by historical test years are uncompensatory may be suspected by stakeholders of poor cost management. However, research shows that a utility's unit cost trend is determined primarily by business conditions over which it has little control. These include the trends in input price inflation, average use, and the need for plant additions.
3) In a rising unit cost environment, the ability of a utility to "take a hair cut" between the historical test year and the rate year is limited. Long term performance gains involve upfront costs. Deferment of expenses lowers cost today at the expense of higher costs in the future.
4) Absent favorable operating conditions, the rise in a utility's unit cost due to changing business conditions may be so great that it is unable to earn its allowed rate of return under historical test year rates even with normal productivity gains. As Kamerschen and Paul comment, "while a utility is never guaranteed that it will earn its authorized fair rate of return, if no allowance is made for attrition or the other explosive elements, the utility is denied a realistic opportunity of earning the permitted rate of return."[11] In this situation, rates produced by historical test years are inherently unjust and unreasonable. This can prompt the investment community to downgrade its credit valuations, not just for the subject utility but for other utilities in the same jurisdiction.
5) Firms in competitive markets have ways of coping with rising unit costs that aren't available to utilities. The prices a competitive firm receives for its products will tend to rise at the same pace as the unit cost of its industry. Firms experiencing unit cost growth in excess of growth in sales prices can always scale back their offerings. A utility, in contrast, charges prices set by regulators which may not be reflective of unit cost trends. The utility is obligated to provide service even if prices are non-compensatory due to flawed ratemaking practices.

[11] Kamerschen and Paul *op. cit.* p. 23.

6) Unit cost pressures are not constant over time. Several years of flat unit cost can give way to a sustained period of rising unit cost. Thus, historical test years can produce reasonable results for many years and then become uncompensatory for many years due to rising unit cost. A utility's success at earning its allowed ROE during a string of recent years does not necessarily mean that a forward test year isn't warranted prospectively.
7) Forward test years have major advantages over historical test years in a rising unit cost environment. Rates are more likely to reflect unit cost conditions in the rate year and are, to this extent, more just and reasonable. Customers receive better price signals. Lower operating risk reduces the utility's cost of securing funds in capital markets. This benefit is especially important in periods of large plant additions, when high borrowing costs can have an especially large impact on the embedded cost of debt.
8) Whether or not unit cost is rising, historical test years do not adjust rates for slowdowns in volume growth, between the test year and the rate year, which are due to utility conservation initiatives. They therefore dampen utility incentives to encourage conservation.

1.2.2 Uncertainty

Opponents of forward test years often stress the uncertainty of cost and billing determinant forecasts. Future costs cannot be verified. The changes in business conditions that drive unit cost growth (*e.g.* inflation and the in service dates on looming plant additions) can be hard to predict accurately. The impact that changing business conditions have on unit cost is not always well understood. Opponents also argue that utilities are incented to exaggerate future cost growth and to understate future growth in billing determinants. Cost and billing determinants in a historical test year are, meanwhile, known with certainty.

On the other hand, the projections at issue in a forward test year concern business conditions that are at most two years into the future. A large chunk of future cost, the depreciation and the return on older plant, is known with considerable certainty at the time that the forecast is made. There are many aids in the preparation of credible forecasts, as we discuss further in Section 1.3. Consider also that volatile components of a utility's unit cost (*e.g.* expenses for pensions and uncollectible bills) are often subject to trackers that reduce or eliminate the risk of bad forecasts.

Current test years involve less forecasting uncertainty because the test year is only a year into the future at the time that the rate case is filed. Actual data for some or all months of the test year become available in the course of the proceeding. The accuracy of the methods used to forecast cost and billing determinants can thus be tested against their ability to predict the actuals in some months of the test year.

FTY projections are, in any event, quickly followed by actual data, and a utility that makes forecasts that are consistently biased in its favor will find that its forecasts are discounted in ratemaking. Biased forecasts can even jeopardize a regulator's willingness to use forward test years. The other stakeholders to the rate case process have incentives to bias cost and sales forecasts in the other direction. These circumstances reduce or eliminate the bias of the forecasts on which FTY rates are ultimately based. If the forecast of future cost and output is accurate, the utility will receive revenue that is exactly equal to its cost. FTY rates will be fair to the utility and ratepayer alike, whereas historical test year rates are likely to be biased in a rising (or falling) unit cost environment.

On balance then forward test year rates, while involving some uncertainty, are likely to be more reflective of future business conditions than are historical test year rates in a rising unit cost environment. The uncertainty involved in basing rates on FTYs is no greater than that involved in rate freezes and other kinds of multiyear rate plans that are often approved by regulators. The Michigan Public Service Commission ("PSC") commented, in a recent decision on an FTY rate filing for Consumers Energy, that

> The basis for using a forward test year is to address the problem of regulatory lag between past and future costs. While the advantage of historical data is its objective and verifiable nature, it lacks the necessary forward perspective required in a changing economic environment. An historical test year is by definition not timely and may fail to adequately consider future demands….What is gained by dealing with data that is "known and measurable" can be lost in forcing a utility to operate with outdated numbers.[12]

[12] Michigan PSC *Opinion and Order*, Case U-175645, November 2009.

1.2.3 Regulatory Cost

A third consideration in weighing the advantages of historical and forward test years is regulatory cost. The net impact of forward test years on regulatory cost is difficult to assess. Forward test year rate cases typically do involve higher cost than rate cases based on historical test years because of the need for forecasts.

On the other hand, a number of the major issues in a rate case, including the depreciation rates and the rate of return on common equity, are not markedly more complicated in a forward test year proceeding. Depreciation on existing plant is easy to predict once a depreciation rate is established. Some of the more uncertain components of cost and revenue may be subject to trackers that mitigate rate case controversy. The cost of FTY rate cases falls as jurisdictions gain experience with forecasted evidence. Consider also that in a rising unit cost environment rates based on forward test years can, by reducing earnings attrition, sometimes reduce the frequency of rate cases.

1.2.4 Operating Efficiency

The effect of alternative test year approaches on utility operating efficiency is also frequently discussed in debates on test year approaches. Opponents of forward test years sometimes argue that they weaken utility incentives to operate efficiently. In a rising unit cost environment, an expectation that rates are going to be non-compensatory might encourage utilities to tighten their belts. FTY opponents also argue that a utility wishing to inflate its cost in an historical test year, in an effort to create higher rates in the rate year, would incur a real cost to do so.

On the other hand, the notion that rate cases generally weaken utility performance incentives is a central result of regulatory economics and is not confined to future test years. When a utility is operating under a series of annual rate cases with historical test years, cost savings this year lead quickly to lower rates. The fact that a forward test year involves forecasts does not in and of itself weaken performance incentives. Forward test year forecasts are often linked to actual costs in one or more historical reference years, so the utility must once again incur a real cost if it wishes to bolster its argument for higher costs in the test year.

Consider also that when unit cost is rising, the non-compensatory rates yielded by forward test years may cause utilities to file rate cases more frequently. This weakens performance incentives, and senior managers devote less time to the utility's basic business of providing quality service at a reasonable cost. Analysis by PEG Research has revealed that reducing the frequency of rate cases from one to three years increases a utility's productivity performance by about 50 basis points annually in the long run.[13] We therefore do not expect utility operating incentives to differ significantly between historical and forward test years on balance.

It is, in any event, unreasonable for stakeholders and regulators to acquiesce in non-compensatory HTY rates on the grounds that they encourage utilities to trim "fat" if the existence of fat has not been demonstrated in the rate case. J. Michael Harrison, an administrative law judge with the New York PSC, commented in this regard in a 1979 article on forward test years that

> It is reasonable to set rates conservatively when company's management or operations are significantly and demonstrably poor... Evidence of general management inadequacy, however, is rarely seen in rate cases and ... management normally will be striving to improve efficiency in periods of continuously rising costs. Regulatory commissions certainly have an obligation to monitor operations and management effectiveness, but it does not appear justifiable to indulge in a presumption, absent specific evidence to the contrary, that deficient earnings can be attributed to management shortcomings rather than to unfavorable operating conditions.[14]

1.2.5 Other Considerations

Here are some additional considerations that merit note in a discussion of forward test year pros and cons.

- Forward test years encourage the utility, other stakeholders, and the Commission to focus more attention on the utility's plans for the future. Undesirable trends, such as rising costs that reflect inadequate attention to productivity growth, can be recognized and discouraged in advance of their occurrence. Budgeting is apt to play a more central role in cost management.

[13] See, for example, "Incentive Plan Design for Ontario's Gas Utilities", a presentation made by the senior author in work for the Ontario Energy Board in November 2006.
[14] J. Michael Harrison, "Forecasting Revenue Requirements", *Public Utilities Fortnightly*, March 1979, p. 13.

- Forward test year rate cases sharpen the ability of the regulatory community to undertake and review statistical analyses of unit cost trends. These same skills are useful in the design of multiyear rate plans in which rates are adjusted automatically between rate cases to reflect changing business conditions. Multiyear rate plans can reduce regulatory cost and strengthen utility performance incentives, creating benefits that can be shared with customers.

1.3 Evidentiary Basis for FTY Forecasts

Good evidence on future costs and billing determinants is critical to the effectiveness of forward test year rate cases. The New York PSC stated, in an order rejecting a forward test year for New York State Electric and Gas in 1972, that

> To justify the commission in deviating from its long-standing policy of using an actual test year adjusted for known changes, there must be a full showing that such a change is a practical necessity. This showing must encompass the twin requirements of substantial accuracy and an impending, uncontrollable diminution in profitability.

We have already discussed at some length the kinds of conditions that can cause unit cost to rise between an historical test year and the rate year. We consider here kinds of evidence used in FTY rate cases that increase the confidence of regulators that forecasts are accurate.

Linkage to Historical Data

Utilities in forward test year rate cases usually file detailed and extensive evidence concerning cost and billing determinants in one or more historical reference years.[15] Data for these years are usually subject to normalization and annualization adjustments like those used in historical test year filings. The utility will then present evidence on expected changes in cost and billing determinants between the historical reference year and the test year.[16] Cost projections are often made for the same detailed Uniform System of Account categories that are used in historical test year rate cases. J. Michael Harrison commented in this regard in his 1979 article that "the New York commission's requirement that a verifiable nexus be established between a forecast and an historical base of actual experience is a sine qua non

[15] An historical reference year is sometimes called a "base period".
[16] This sometimes includes a forecast of cost during the rate case year (if different), which is sometimes called the "bridge year".

for forecasting revenue requirements. The burden of proving the reasonableness of its filing remains with the utility company."[17]

Indexation

Indexation is used by several utilities in FTY rate cases to escalate cost items for changing business conditions. Recall from Section 1.2.1 that the growth in the cost of a utility equals the inflation in the prices it pays for inputs plus the growth in its output less the trend in its productivity. The trend in the productivity of utilities tends to be similar to the growth in their output. Testimony just prepared by PEG Research for San Diego Gas & Electric reports that, for a national sample of power distributors, MFP averaged 0.88% annual growth from 1999 to 2008 while the number of customers served averaged 1.37% average annual growth.[18] An assumption that productivity growth equals output growth makes it possible to escalate cost from historical reference year(s) values by the forecasted growth in prices. This is the most common use of indexing in FTY forecasts.

The United States is fortunate to have available some of the best data in the world on utility input price trends. One company, Whitman, Requardt and Associates, has for decades published "Handy Whitman Indexes" of trends in the construction costs of both gas and electric utilities.[19] These are available for six geographic regions of the United States for detailed asset classes. Another company, Global Insight, has a *Power Planner* service that has forecasts, updated quarterly, of construction cost indexes. Global Insight also forecasts inflation in the prices of labor, materials, and services used by gas and electric utilities.[20] The materials and service ("M&S") price indexes are available for the detailed O&M expense categories that are itemized in the FERC's Uniform System of Accounts. Global Insight input price indexes have been used for many years to adjust revenue requirements in the multiyear rate plans of California gas and electric utilities.

Some utilities instead escalate O&M expenses in rate cases using familiar macroeconomic price indexes. The gross domestic product price index ("GDPPI") is often preferred for this purpose to the better known consumer price index because the GDPPI assigns less weight to price volatile commodities, such as food and energy, which do not

[17] J. Michael Harrison, *op. cit.*, p. 13.
[18] Mark Newton Lowry *et al.*, *Productivity Research for San Diego Gas & Electric,* August 2010.
[19] Whitman, Requardt & Associates LLP, "The Handy-Whitman Index of Public Utility Construction Costs".
[20] A discussion of an early use of detailed inflation forecasts in ratemaking is found in Michael J. Riley and H. Kendall Hobbs, Jr. "The Connecticut Solution to Attrition", *Public Utilities Fortnightly*, November 1982.

loom large in base rate input costs. Our research over the years has found that the GDPPI and CPI both tend to understate escalation in the prices of utility O&M inputs. One reason is that they are measures of inflation in the economy's prices of final goods and services and therefore reflect the productivity growth of the U.S. economy, which has been substantial in recent years. In a recent report for Hawaiian Electric, for instance, PEG found that from 1996 to 2007 the GDPPI averaged 2.21% average annual growth whereas an index of the O&M input prices paid by HECO averaged 3.05% average growth.[21] The GDPPI should therefore inspire confidence as an O&M escalator that often yields reasonable results for customers.

Simple Trend Analyses

Simple approaches to forecasting based on historical trends can, if well designed, strike a reasonable balance between the desire of regulators for accuracy and simplicity. For example, a given cost item can equal its adjusted value in the historical reference year, plus a one or two-year escalation for the average annual growth of this cost for a group of peer utilities in recent years. This approach is more sensible to the extent that the recent inflation, productivity, and output trends of the peers are similar to those that the subject utility will experience in the near future. A refinement on this general approach would be to assume a trend in cost *per customer* equal to the recent historical trend of peer utilities and then to reach cost by adding a forecast of the utility's own customer growth. Simple methods like these have counterparts for the forecasting of billing determinants. For example, the volume of residential sales in a future test year can be forecasted as the expected number of customers multiplied by the expected volume per customer, where the latter is allowed to differ from the normalized value(s) in the historical reference year(s) by its normalized trend in the last three years.

Budgeting

Some utilities use the same figures in forward test year filings that they use in their own budgeting process.

[21] Mark Newton Lowry *et al.*, *Revenue Decoupling for Hawaiian Electric Companies*, Pacific Economics Group, January 2009. pp. 65-66.

Econometric Modeling

Econometric modeling is used by several utilities in FTY cost and billing determinant projections. In an econometric model, the variable to be forecasted is posited to be a function of one or more external business conditions. Model parameters are estimated using historical data on the variable to be forecasted and the business conditions. A rich theoretical and empirical literature is available to guide model development. Given forecasts of the business conditions, the model can forecast how cost will grow between one or more historical reference years and the forward test year.

Benchmarking

Utilities can bolster the confidence of regulators in their FTY cost forecasts by benchmarking them using data from other utilities. A variety of benchmarking methods are available, ranging from econometric modeling to peer group comparisons that use simple unit cost metrics. Public Service of Colorado, for instance, recently filed a study in an FTY rate case filing that benchmarked their non-fuel O&M expense forecast.[22] The study used an econometric benchmarking model as well as unit cost metrics for a Western Interconnect peer group. The authors found that the forecasted expenses reflected a high level of operating efficiency.

[22] See Public Service Company of Colorado's Exhibit MNL-1 in docket 09AL-299E before the Public Utilities Commission of Colorado, filed October 13, 2009.

2. TEST YEAR HISTORY AND PRECEDENTS

2.1 A Brief History

Few states have laws on the books that mandate a particular test year approach. Statutes instead commonly feature more general provisions on regulation such as guidelines that rates be just and reasonable, that terms of service be non-discriminatory, and that service be of good quality. Flexibility with respect to test years is also encouraged by the Supreme Court's influential *Hope* decision, which held that

> The Commission was not bound to the use of any single formula or combination of formulae in determining rates. Under the statutory [Natural Gas Act] standard of "just and reasonable" it is the result reached and not the method which is controlling...If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end.[23]

Historical test years were nonetheless the norm in the early history of electric utility rate cases, and this reflects the prevalence over many years of business conditions that were conducive to slow unit cost growth. Slow price inflation was a contributing factor. Table 1 shows the history of GDPPI inflation in the United States from 1930 to 2009. It can be seen that inflation was negative in most years of the 1930s but was brisk during World War II, the immediate post war years, and in 1951. After the Korean War, the table shows that GDPPI inflation averaged only 1.74% annually in the 1952-1965 period.

Table 1 also shows the trend in the MFP index for the electric, gas, and sanitary sector of the U.S. economy. This index was computed by the U.S. Bureau of Labor Statistics ("BLS") for many years and was sensitive to the productivity trend in the electric utility industry due to the industry's disproportionately large size. It can be seen that the productivity growth of the electric, gas, and sanitary sector was extraordinarily rapid during the 1952-65 period, averaging 4.13% per annum. This was more than double the MFP index trend for the U.S. non-farm private business sector as a whole.

Under these favorable operating conditions, the unit cost of the electric utilities was typically stable or declining.[24] Rate cases were rare and historical test years were the norm in the rate cases that did occur. Regulators gained confidence that the matching principle could

[23] 320 U.S. 591.
[24] See Paul Joskow, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation", *Journal of Law and Economics*, 1974 for an insightful discussion of some of this history.

Table 1

U.S. Inflation and Productivity Trends

		GDP Price Index		Multifactor Productivity: Private Non-Farm Business		Multifactor Productivity: Electric, Gas & Sanitary Sector	
	Year	Index	Growth	Index	Growth	Index	Growth
	1929	10.6		NA	NA	NA	NA
	1930	10.2	-3.94%	NA	NA	NA	NA
	1931	9.2	-10.45%	NA	NA	NA	NA
	1932	8.1	-12.08%	NA	NA	NA	NA
	1933	7.9	-2.66%	NA	NA	NA	NA
	1934	8.3	4.78%	NA	NA	NA	NA
	1935	8.5	1.97%	NA	NA	NA	NA
	1936	8.6	1.09%	NA	NA	NA	NA
	1937	8.9	3.61%	NA	NA	NA	NA
	1938	8.7	-1.90%	NA	NA	NA	NA
	1939	8.6	-1.27%	NA	NA	NA	NA
	1940	8.7	0.87%	NA	NA	NA	NA
	1941	9.2	6.32%	NA	NA	NA	NA
	1942	10.0	7.91%	NA	NA	NA	NA
	1943	10.6	5.47%	NA	NA	NA	NA
	1944	10.8	2.37%	NA	NA	NA	NA
	1945	11.1	2.52%	NA	NA	NA	NA
	1946	12.4	10.90%	NA	NA	NA	NA
	1947	13.7	10.54%	NA	NA	NA	NA
	1948	14.5	5.52%	53.0	NA	37.1	NA
	1949	14.5	-0.06%	53.8	1.41%	37.7	1.66%
	1950	14.6	0.78%	57.2	6.08%	40.5	7.20%
	1951	15.6	6.66%	58.6	2.47%	44.4	9.16%
	1952	16.0	2.15%	59.0	0.67%	46.3	4.19%
	1953	16.2	1.26%	59.9	1.59%	48.1	3.80%
	1954	16.3	1.01%	59.9	-0.12%	50.0	4.01%
	1955	16.6	1.42%	62.4	4.15%	53.9	7.41%
	1956	17.1	3.39%	61.6	-1.33%	56.6	4.99%
	1957	17.7	3.44%	62.3	1.11%	58.7	3.59%
	1958	18.1	2.28%	62.4	0.29%	60.3	2.71%
	1959	18.3	1.13%	65.2	4.35%	64.1	6.10%
	1960	18.6	1.39%	65.5	0.51%	66.0	2.95%
	1961	18.8	1.12%	66.6	1.54%	67.7	2.41%
	1962	19.1	1.36%	68.9	3.46%	70.9	4.68%
	1963	19.3	1.05%	70.8	2.68%	72.3	2.02%
	1964	19.6	1.54%	73.5	3.72%	76.1	5.02%
	1965	19.9	1.80%	75.6	2.82%	79.2	4.00%
	1966	20.5	2.80%	77.7	2.82%	82.4	4.07%
	1967	21.1	3.03%	77.8	0.06%	85.0	3.01%
	1968	22.0	4.16%	79.8	2.56%	88.8	4.42%
	1969	23.1	4.82%	79.2	-0.76%	91.2	2.69%
	1970	24.3	5.14%	78.8	-0.50%	92.7	1.56%
	1971	25.5	4.88%	81.3	3.11%	93.8	1.21%
	1972	26.6	4.22%	83.7	2.87%	95.4	1.70%
	1973	28.1	5.39%	86.1	2.87%	97.2	1.88%
	1974	30.7	8.66%	83.2	-3.35%	94.0	-3.31%
	1975	33.6	9.06%	83.6	0.43%	94.2	0.18%
	1976	35.5	5.58%	86.8	3.77%	95.4	1.28%
	1977	37.8	6.17%	88.1	1.46%	95.2	-0.25%
	1978	40.4	6.78%	89.4	1.47%	95.1	-0.04%
	1979	43.8	7.99%	88.8	-0.67%	94.0	-1.21%
	1980	47.8	8.75%	86.9	-2.20%	93.5	-0.53%
	1981	52.3	9.01%	86.5	-0.42%	93.5	0.04%
	1982	55.5	5.92%	83.5	-3.59%	92.6	-1.04%
	1983	57.7	3.87%	86.6	3.68%	91.4	-1.23%
	1984	59.8	3.69%	88.7	2.35%	94.5	3.34%
	1985	61.6	2.98%	89.2	0.65%	94.4	-0.16%
	1986	63.0	2.20%	90.6	1.47%	94.7	0.35%
	1987	64.8	2.76%	90.7	0.16%	94.8	0.04%
	1988	67.0	3.38%	91.7	1.04%	98.5	3.84%
	1989	69.5	3.71%	91.7	0.00%	98.9	0.44%
	1990	72.2	3.80%	92.0	0.40%	100.4	1.49%
	1991	74.8	3.47%	91.3	-0.80%	100.2	-0.18%
	1992	76.5	2.35%	93.5	2.39%	100.0	-0.21%
	1993	78.2	2.18%	93.7	0.18%	102.6	2.52%
	1994	79.9	2.08%	94.4	0.78%	103.2	0.67%
	1995	81.5	2.06%	94.5	0.09%	105.6	2.22%
	1996	83.1	1.88%	95.8	1.42%	106.9	1.24%
	1997	84.6	1.76%	96.5	0.66%	106.9	-0.02%
	1998	85.5	1.12%	97.7	1.28%	107.0	0.11%
	1999	86.8	1.46%	99.0	1.27%	NA	NA
	2000	88.6	2.15%	100.0	1.05%	NA	NA
	2001	90.7	2.24%	100.4	0.39%	NA	NA
	2002	92.1	1.60%	102.5	2.08%	NA	NA
	2003	94.1	2.13%	105.2	2.60%	NA	NA
	2004	96.8	2.80%	108.0	2.60%	NA	NA
	2005	100.0	3.28%	109.3	1.26%	NA	NA
	2006	103.3	3.21%	109.9	0.51%	NA	NA
	2007	106.2	2.82%	110.1	0.21%	NA	NA
	2008	108.5	2.11%	111.4	1.13%	NA	NA
	2009	109.7	1.16%	NA	NA	NA	NA
Averages	**1952-1965**		**1.74%**		**1.82%**		**4.13%**
	1973-1981		**7.49%**		**0.37%**		**-0.22%**
	1982-1991		**3.58%**		**0.54%**		**0.69%**
	1992-2003		**1.92%**		**1.18%**		**NA**
	2004-2008		**2.84%**		**1.14%**		**NA**

yield just and reasonable rates.

The unit cost growth of electric utilities accelerated in the late 1960s and remained high for about two decades thereafter for several reasons.

- Price inflation accelerated, spurred initially by the Vietnam War and subsequently by the oil price shocks of 1974-75 and 1979-80. During the 1973-81 period, GDPPI inflation averaged 7.49% annually. Inflation thereafter slowed but still averaged 3.58% annually during the 1982-91 period.
- Rising utility rates and slowing economic growth slowed growth in use per customer.
- Utility productivity growth, far from keeping pace with inflation, slowed substantially falling by 0.22% annually on average in the 1973-1981 period and averaging only 0.69% annual growth in the 1982-91 period. Factors contributing to the slowdown included the exhaustion of scale economies by some of the nation's larger electric utilities and the propensity of some utilities to continue making major plant additions despite slower demand growth.

Under these changed conditions, utilities in the two decades after 1967 sought financial relief by filing frequent rate cases. However, many utilities found that they could not earn their allowed ROE under newly established rates. One author commented in 1974, a particularly bad year, that "it would be difficult, if not impossible, to find a utility which has been able in the first year in which a rate increase was in effect to earn the return on which the rate increase was predicted".[25] A study found that the earned ROE on equity in the electric utility industry was more than 200 basis points below the allowed rate of return on average in 1974, 1979, and 1980.[26] Interest coverage fell markedly for many utilities, limiting their ability to issue new debt. Financing of new investments required greater reliance on issuance of new common stock, and the value of stock fell below the book value of assets in many cases. Articles about attrition and regulatory lag appeared with regularity in the trade press.[27]

[25] W. Truslow Hyde, "It Could Not Happen Here – But it Did", *Public Utilities Fortnightly*, June 1974.
[26] Walter G. French, "On the Attrition of Utility Earnings", *Public Utilities Fortnightly*, February 1981.
[27] See, as another example, Theodore F. Brophy, "The Utility Problem of Regulatory Lag", *Public Utilities Fortnightly*, January 1975.

Regulators responded to this situation with an array of measures, some of which had been used at one time or another in the past. The measures included interim rate increases; the inclusion of construction work in progress ("CWIP") in rate base; more widespread use of fuel adjustment clauses; the addition of an "attrition allowance" to the target ROE, and more widespread use of forward and hybrid test years. Adopters of FTYs in these years of brisk unit cost growth included the Federal Energy Regulatory Commission ("FERC") and state commissions in California, Connecticut, Florida, Georgia, Hawaii, and New York.

Some of these states initially experimented with hybrid test years which, as we have noted, make it possible to update rate filings as actual data for the later months of the test year become available. J. Michael Harrison explained in his 1979 article some grounds for dissatisfaction with hybrid test year experiments:

> Parties charged with testing or contesting a utility's rate case presentation were faced with figures and issues that changed and shifted through all phases of the case. Even after their direct evidentiary presentations were made, these parties were faced with a required reevaluation of their positions and the possibility that a host of new issues would be created by emerging actual data. The commission staff, which in New York bore the brunt of this burden, faced an almost impossible task of analyzing new data, even as its case went to the administrative law judge or commission for decision. It became clear that the value of the already completed hearings was being seriously undermined.[28]

The New York Commission decided in 1977 to move to fully forecasted test years consisting of the first twelve months expected under the new rates.[29]

The need for forward test years subsided with the slowdown of unit cost growth that occurred in the electric utility industry in the 1990s. This slowdown was driven primarily by a partial reversal of the business conditions that had previously caused brisk unit cost growth. During the 1992-2003 period GDPPI growth averaged only 1.92% per year. Yields on newly issued long term bonds fell substantially as the market lowered its expectation of future inflation. The productivity growth of the electric, gas, and sanitary sectors increased modestly, averaging 0.94% annually during the 1992-98 period, a trend similar to that of the private business sector. One reason for the productivity rebound was a slowdown in plant additions as the industry increased utilization of the generation and transmission capacity

[28] J. Michael Harrison, *op. cit.*, p. 12.
[29] New York Public Service Commission, "Statement of Policy on Test Periods in Major Rate Proceedings", November 1977.

built in the previous twenty years. Several electric utilities operated under base rate freezes during these years. Their willingness to agree to freezes reflected in part the generally favorable unit cost conditions but sometimes also reflected an expected spurt of productivity growth due to participation in mergers or acquisitions.

Interest in forward test years has renewed for electric utilities in recent years due to a renewed growth in unit cost, which is discussed in more detail in Section 3.1 below. We note here that general inflation accelerated after 2003, with GDPPI growth averaging 2.84% annually during the 2004-2008 period. Inflation slowed in 2009 but will likely rebound as the world economy recovers from the recession. Utility investment needs increased during the period to replace aging facilities, reverse declining generation capacity margins, implement "smart grid" technologies, and meet the rising demand for transmission services to reach remote sources of renewable energy and promote bulk power market competition. Growth in average use has slowed with slowing economic growth and new initiatives to promote energy conservation.

Interest in forward test years has been especially keen in the American west. Brisk economic growth in most western states has increased the need for plant additions. Here is a brief summary of changing test year policies in selected states.

Colorado

In Colorado, the commission rejected an FTY request by Public Service of Colorado in 1993 but acknowledged that "the purpose of a test year is to provide, as closely as possible, an interrelated picture of revenue, expense, and investment reasonably representative of the interrelationships that will be in place at the time the new rates proposed in a rate case will be in effect".[30] The commission did not forbid FTY evidence and encouraged the company to consider a *current* test year, an option that it said "might provide a promising mixture of comfort and flexibility acceptable to the parties and the commission.[31]

Public Service filed FTY evidence in a 2008 rate case but the approved settlement in the case was based on historical test year evidence.[32] In May 2009, Public Service again filed FTY evidence as it sought to include in its cost of service some major plant additions,

[30] PUC Colorado Decision No. C93-1346 in Docket No. 93S-001EG, October 1993, pp. 21-22.
[31] *Ibid*, p. 40.
[32] Docket No. 08S-520E.

including a new coal-fired generating unit and a smart grid build out, which would come online in late 2009 or 2010.[33] A settlement agreement, approved with modifications, based the revenue requirement on a historical 2008 test year with extraordinary adjustments to include the cost of the impending major plant additions. The company agreed not to file a rate case for two years.

This settlement also indicated an expectation that the company would file FTY evidence in its next rate case. It commits the company to provide companion historical test year evidence, including a detailed analysis of deviations between HTY and FTY results. The Company agreed to work with interested parties on reporting requirements with respect to such deviation analyses in order to facilitate the review of future cases.

Idaho

In Idaho the largest electric utility, Idaho Power, successfully used a hybrid test year in a rate case filing in 2003. In a 2009 filing it successfully used a test year beginning in January 2009.[34] This was essentially a current FTY.

Illinois

The move to forward test years is not confined to western states. Illinois utilities have long retained the right to file FTY rate cases and Integrys recently did so successfully for its North Shore Gas and Peoples Gas Light and Coke units.[35] Peoples has a major need to increase replacement investments in its aging system, which serves Chicago.

Michigan

In Michigan, utilities have used varied test year approaches. Recent legislation (2008 PA 286) explicitly sanctions forward test year filings. The law also permits utilities to "self-implement" interim rates if rate cases aren't resolved in 180 days. Consumers Energy and Detroit Edison have recently filed FTY rate cases successfully.

New Mexico

In New Mexico a bill was passed in 2009 that allows the state commission to use forward test years in electric and gas rate proceedings. The bill states that

[33] Docket No. 09AL-299E.
[34] Docket No. IPC-E-09-10.
[35] Dockets No. 09-0166 and 09-0167.

> The commission shall set rates based on a test period that the commission determines best reflects the conditions to be experienced during the period when the rates determined by the commission take effect. If a future test period is proposed, the commission shall give due consideration that the future test period may best reflect those conditions.[36]

The Bill was supported by majority voice vote of the New Mexico Public Regulation Commission. Public Service of New Mexico recently filed an FTY rate case.

Utah

Utah statutes were amended in 2003 to allow hybrid and forward test years for gas and electric utilities. The amended statutes state that

> If in the commission's determination of just and reasonable rates the commission uses a test period, the commission shall select a test period that, on the basis of the evidence, the commission finds best reflects the conditions that a public utility will encounter during the period when the rates determined by the commission will be in effect.[37]

The choice of a test year has since become an issue in the early stages of rate cases. In 2004, for example, PacifiCorp [d/b/a Rocky Mountain Power ("RMP")] filed a rate case based on a forward test year. It defended the FTY on the grounds that its costs were increasing due to rapid system growth and a plan to improve system reliability. An unopposed Test Year Stipulation acknowledged that the FTY was the most sensible test year for this case and provided for a task force to address test period procedural issues. The terms of the stipulation were not binding for future proceedings. The Commission commented in its order approving the stipulation that

> Each case needs to be considered on its own merits and the test period selected should be the most appropriate for that case. The test period selected for a utility in a particular case may not be appropriate for another utility or even the same utility in a different case. Some of the factors that need to be considered in selecting a test period include the general level of inflation, changes in the utility's investment, revenues, or expenses, changes in utility services, availability and accuracy of data to the parties, ability to synchronize the utility's investment, revenues, and expenses, whether the utility is in a cost

[36] New Mexico Senate Bill 477, 2009.
[37] Utah Code Annotated Section 54-4-4 (3).

> increasing or cost declining status, incentives to efficient management and operation, and the length of time the new rates are expected to be in effect.[38]

In December 2007, RMP filed a rate case based on a forward test year beginning in July 2008.[39] The Commission instead chose a current FTY beginning in January 2008. The Company was compelled to update its testimony to reflect the sanctioned test year. In its final decision in the case, the Commission instructed the Company to file a semi-annual "variance report" comparing its actual operating results to its rate case forecasts.

In April 2009, RMP filed a notice of intent to file a rate case in June 2009 based on a forward test year beginning in January 2010. A high level of capital investment was emphasized in advocating the need for an FTY. The Commission approved a Test Period Stipulation providing for a current FTY beginning in June 2009. The decision notes that the Division of Public Utilities argued in support of the stipulation that

> the stipulated test period, combined with the opportunity for the Company to request alternative cost recovery treatment for major plant additions, will balance the interest of the Company in reducing regulatory lag and the interests of customers by reducing the risks associated with the timing and cost of major capital additions projected to be completed 18 months into the future.[40]

Wyoming

In Wyoming, a stipulation approved in 2006 provided that RMP (d/b/a PacifiCorp) could, on a one time trial basis, file a rate case based on a forward test year. RMP filed a rate case in June 2007 using an FTY ending in August 2008. The Wyoming Public Service Commission approved a rate settlement based on the forecasts for this test year. They indicated a willingness to hear forward test year evidence in the general rate case but required the company to submit conventional historical test year evidence as well. The Commission also directed the company to prepare a report comparing its actual cost and billing determinants for the current test year to those which the company forecasted in the proceeding. In the event, the variance report stated that the company had overestimated its

[38] Public Service Commission of Utah, "Order Approving Test Period Stipulation", Docket 04-035-42, October 2004.
[39] Public Service Commission of Utah, "Order on Test Period", Docket No. 07-035-93, February 2008.
[40] Public Service Commission of Utah, "Report and Order on Test Period Stipulation", Docket No. 09-035-23, June 2009.

cost by a small amount but overestimated its revenue and on balance did not earn its allowed rate of return for the year.

In July 2008, RMP filed a new rate case with a current FTY ending in June 2009 using calendar 2007 as a historical reference year. The company emphasized in its case the inability of historical test year rates to compensate the utility for sizable new investments in its system. The Commission approved a settlement that included a provision that RMP file historical test year evidence as well as any FTY evidence in its next rate proceeding.[41] RMP will continue to file operating results that will permit the Commission to review the accuracy of its FTY forecasts.

2.2 Current Status

Table 2 and Figure 1 detail the test year approaches that are currently in use across the United States. It can be seen that historical test years are now used by most large IOUs in less than twenty U.S. jurisdictions. Nearly as many jurisdictions (AL, CA, CT, FL, GA, HI, ME, MI, MN, MS, NY, OR, RI, TN, WI, and the FERC) use forward test years routinely, at least for larger utilities. Forward test years are also used in several Canadian jurisdictions. Four jurisdictions (AR, OH, NJ, & PA) use hybrid test years. An additional 13 jurisdictions are not neatly categorized. Here are some examples.

- Large utilities in Illinois, Kentucky, Maryland, and North Dakota utilities use various test years.
- As previously noted, test years used by utilities in Utah and Wyoming depend on conditions at the time of filing and New Mexico is heading in that direction.

2.3 Conclusions

In Section 1.2 we noted that the matching principle used in historical test year rate cases is based on the assumption that growth in billing determinants matches cost growth so that unit cost is stable. This is true when growth in utility productivity and average use somehow combine to offset the cost impact of input price growth. We report in this chapter that conditions like these have not been normal for electric utilities since the 1960s. Periods of unit cost stability can still occur, but are apt to be followed by periods of rising unit cost.

[41] Wyoming PSC Docket Number 20000-333-ER-08 (Record No. 11824), May 2009.

Table 2

Test Year Approaches of U.S. Jurisdictions

Forward (16)

State	Notes
Alabama	Alabama Power's Rate Stabilization and Equalization Factor is forward looking.
California	Cost is based on a historical test year that is escalated to a future rate year.
Connecticut	
FERC	Rate cases use forward test years while formula rate plans tend to use HTYs.
Florida	
Georgia	
Hawaii	
Maine	Cost is based on a historical test year that is escalated to a future rate year.
Michigan	
Minnesota	
Mississippi	
New York	
Oregon	
Rhode Island	Cost is based on a historical test year that is escalated to a future rate year.
Tennessee	
Wisconsin	

Hybrid (4)

State	Notes
Arkansas	
Ohio	
New Jersey	
Pennsylvania	

Transitional/Varying (13)

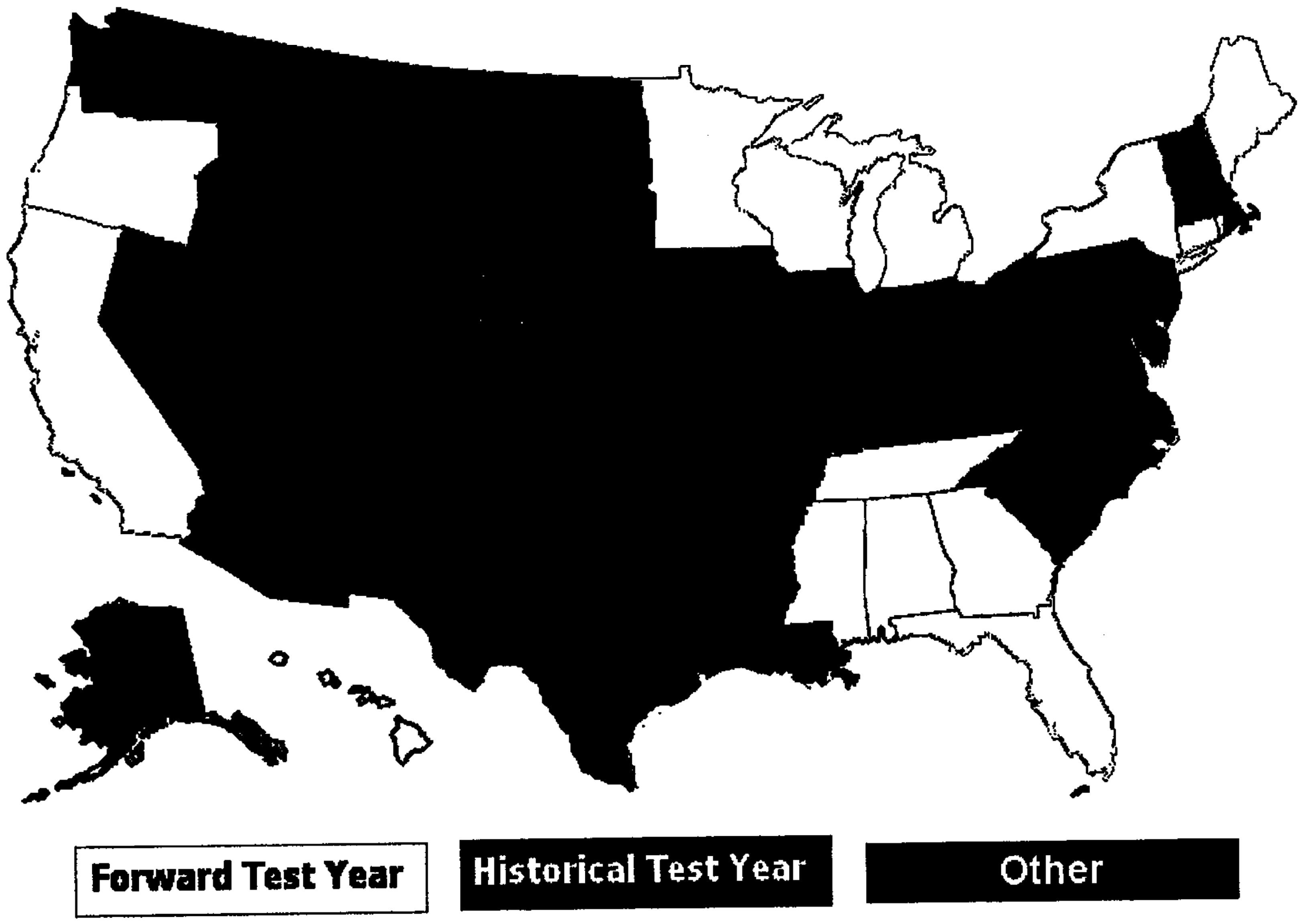
Utility Name	Notes
Colorado	Public Service of Colorado can file FTY evidence. No FTY rates have yet been approved but the most recent case made extraordinary HTY adjustments.
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently.
Delaware	Before restructuring FTY filings were common, but companies have used HTY in recent filings.
Idaho	
Illinois	Historic test years are the norm in IL. However, utilities have the right to make FTY filings and an FTY was accepted in a recent rate case of the Integrys gas utilities.
Kentucky	FTYs are legally authorized, but only Duke Energy has utilized them to date.
Louisiana	Cleco Power frequently uses hybrid test years. Entergy New Orleans recently had a hybrid test year approved via settlement.
Maryland	Baltimore Gas & Electric tends to file hybrid test years while other utilities tend to file historical test years.
Missouri	Utilities have the option to file hybrid year forecasts that are trued up during the course of the proceeding.
New Mexico	Recently passed law allows for use of FTY, but no rate case with an FTY has yet been approved.
North Dakota	Utilities use various test years including FTYs.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently had FTYs approved.

Historical (19)

Utility Name	Notes
Alaska	
Arizona	
Indiana	
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs in its jurisdiction. Gas companies are legally authorized to use FTYs, but no gas company has had FTY rates approved.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

Figure 1

Map of Jurisdictions by Approved Test Year



Numerous regulators have moved away from historical test years in periods when unit cost is rising. Historical test year jurisdictions are now in the minority.

3. EMPIRICAL SUPPORT FOR FORWARD TEST YEARS

3.1 Unit Cost Trends of U.S. Electric Utilities

In Section 1.2 we detailed the key role that the trend in the unit cost of utilities has in determining the reasonableness of historical test years and the need for forward test years. In original research for this paper, we have calculated the unit cost trends of a sample of vertically integrated electric utilities ("VIEUs"). In this section, we explain our research methods in some detail before discussing the results.

3.1.1 Data

The primary source of utility cost date used in the study was the FERC Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Unit cost calculations also require data on billing determinants. Data on the number of customers served were drawn from FERC Form 1. Data on delivery volumes were drawn from Form EIA 861. The FERC Form 1 and Form EIA 861 data used in this study were gathered by SNL Financial, a respected commercial vendor.

Data were considered for inclusion in the sample from all major investor-owned VIEUs that did not offer gas distribution service or sell or spin off the bulk of their transmission assets in recent years. To be included in the study the data were required, additionally, to be plausible and not unduly burdensome to process. Data from the thirty four companies listed in Table 3 were used in the unit cost research. The sample period was 1996-2008. The year 2008 is the latest for which the requisite data were available when the study was prepared.

Supplemental data sources were used to measure input price trends. Handy Whitman indexes were used to measure electric utility construction cost trends. Global Insight indexes were used to measure trends in the prices of electric utility materials and services. Employment cost indexes prepared by the BLS were used to measure trends in labor prices. Regulatory Research Associates data was used to measure trends in target ROEs approved by regulators.

Table 3

Utilities Included in the Unit Cost Research

Company
Alabama Power
Appalachian Power
Arizona Public Service
Black Hills Power
Carolina Power & Light
Cleco Power
Columbus Southern Power
Dayton Power and Light
Duke Energy Carolinas
Empire District Electric
Entergy Arkansas
Florida Power & Light
Florida Power
Georgia Power
Gulf Power
Idaho Power
Indianapolis Power & Light
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Minnesota Power
Mississippi Power
Nevada Power
Ohio Power
Oklahoma Gas and Electric
Otter Tail Power
PacifiCorp
Portland General Electric
Public Service Company of Oklahoma
Southwestern Electric Power
Southwestern Public Service
Tampa Electric
Tucson Electric Power
Virginia Electric and Power

Number of utilities in sample: 34

3.1.2 DEFINITION OF UNIT COST

In Section 1.2.1 we discussed a measure of unit cost growth that is relevant in the appraisal of test years. It is constructed by taking the difference between growth in the net cost of base rate inputs and the growth in an index of utility billing determinants. For each sampled utility, we calculated the total cost of base rate inputs net of taxes as the sum of non-energy O&M expenses, depreciation, amortization, and return on rate base. Non-energy O&M expenses were calculated as total O&M expenses less customer service and information expenses and energy expenses that included those for steam power generation fuel, nuclear power generation fuel, other power generation fuel, and purchased power.[42] [43]

Return on rate base was calculated as the value of the rate base times a weighted average cost of capital ("WACC"). In constructing the WACC we assumed 50/50 weights for debt and common equity. The rate of return on debt was calculated as the ratio of the interest payments of electric utilities to the value of their debt as reported on the FERC Form 1. The ROE was calculated as the average applicable allowed ROEs of electric utilities as reported by Regulatory Research Associates.[44] The rate base for each utility was calculated as its net plant value less net accumulated deferred income taxes plus the value of its fuel, material, and supply inventories.

We reduced the base rate cost thus calculated by two kinds of "non-core" revenues, as is common in the calculation of retail base rate revenue requirements. One item deducted was Other Operating Revenue. This is the revenue from miscellaneous goods and services that include bulk power wheeling. The other component of non-core revenues was an estimate of the margin from power sales for resale.[45]

The growth in the billing determinant index used in our study is a weighted average of the growth in important billing determinants of electric utilities. The determinants used in index construction were the numbers of residential, commercial, and other retail customers

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[42] Customer service and information expenses were excluded because they tended to rise over the sample period due to expanding demand-side management programs. The cost of DSM programs is typically recovered using tracker-rider mechanisms.
[43] We also excluded the Other Expenses category of Other Power Supply Expenses. We believe that large and volatile commodity-related costs are sometimes reported in this category.
[44] In this calculation, we assumed that the target ROE approved for a utility in its most recent rate case was applicable until a new target ROE was approved.
[45] These margins were computed as the difference between sales for resale revenue and an estimate of the energy commodity costs used in power supply.

and the corresponding delivery volumes.[46] We weather normalized the volumes using econometric demand research. In constructing the index, the trends in the billing determinants thus assembled were weighted by our estimates of the typical shares of individual billing determinants in the base rate revenue requirements of VIEUs.[47] The estimates were drawn from a perusal of recent VIEU rate case filings.

3.1.3 Unit Cost Results

Unit Cost Trends

The average annual trends of the sampled utilities in their cost, billing determinants, and unit cost can be found in Table 4 and Figure 2. It can be seen that unit cost declined by a modest 0.78% annually on average in the 1996-2002 period as average growth in billing determinants exceeded average growth in cost. The average growth in unit cost was positive in only one year of this period. These results suggest that, under typical operating conditions, historical test years would have yielded compensatory outcomes in rate cases during this period.

In the 2003-2008 period, on the other hand, it can be seen that unit cost grew briskly, averaging about 2.31% annually. Utilities experienced unit cost growth on average in every year of the period. Cost averaged 1.98% annual growth from 1996 to 2002 and 4.36% annual growth thereafter. The normalized growth of billing determinants averaged 2.75% per annum through 2002 but only 2.05% per annum thereafter. Thus, growth in billing determinants slowed despite marked acceleration of cost growth.

Earnings Impact

To consider the earnings attrition resulting from 2.3% annual unit cost growth, consider that if the typical company in the sample earned its target ROE it would constitute about 13% of the total cost of its base rate inputs. Assuming two years of 2.3% unit cost growth, revenue based on prices reflecting only the normalized business conditions of the historical test year would be expected to result in a 4.45% base rate revenue shortfall. If there was no tax adjustment, this would reduce the return on equity by about 35%. Assuming

[46] The retail peak demands of commercial and industrial customers are also important billing determinants but data on these were unavailable.

[47] We assigned the base rate revenue shares corresponding to demand charges to the "other retail" delivery volume, expecting that these volumes have trends that are similar to those of demand charge billing determinants.

Table 4

Trends in the Unit Cost of US Vertically Integrated Utilities

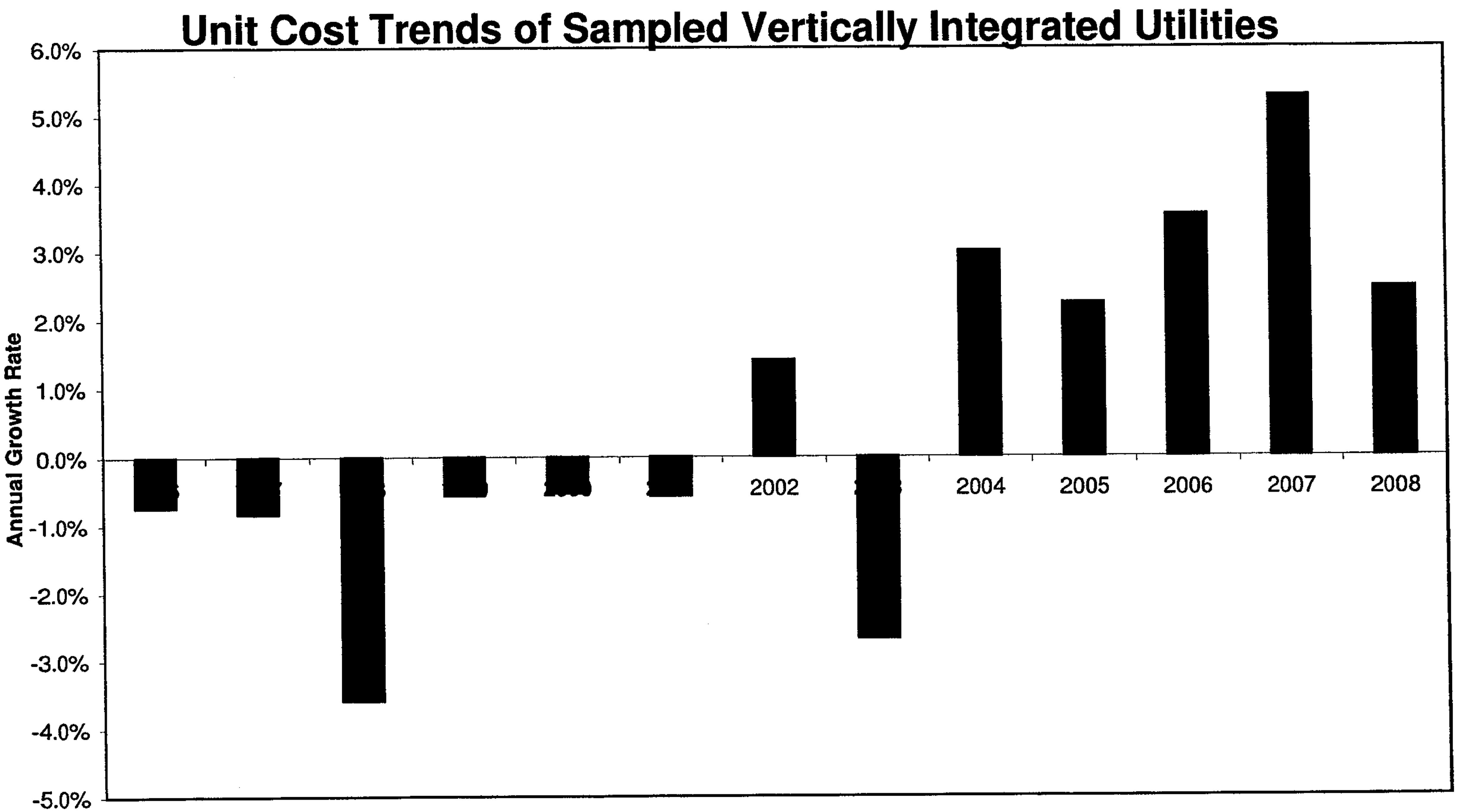
Sample Average Annual Growth Rates, Unweighted

Year	Cost[1]	Billing Determinants[2]	Unit Cost
1996	2.8%	3.5%	-0.7%
1997	1.4%	2.2%	-0.8%
1998	-0.7%	2.9%	-3.6%
1999	2.5%	3.0%	-0.6%
2000	3.4%	4.0%	-0.5%
2001	0.9%	1.4%	-0.6%
2002	3.6%	2.2%	1.4%
2003	1.6%	4.3%	-2.7%
2004	4.6%	1.6%	3.0%
2005	4.0%	1.8%	2.2%
2006	5.0%	1.5%	3.5%
2007	7.9%	2.6%	5.3%
2008	3.0%	0.5%	2.5%
Average Annual Growth Rates			
1996-2008	**3.08%**	**2.43%**	**0.65%**
1996-2002	**1.98%**	**2.75%**	**-0.78%**
2003-2008	**4.36%**	**2.05%**	**2.31%**

[1] The net cost formula is (Total O&M Expenses - Energy O&M Expenses - Customer Service and Information Expenses) + (Depreciation + Amortization + WACC x Rate Base) - (Other Operating Revenues + Estimated Resale Margin). The source of the cost data is FERC Form 1.

[2] The annual growth in billing determinants is a weighted average of the growth in residential, commercial, and other retail delivery volumes and customers served. The weights are shares in the base rate revenue requirement that are typical of vertically integrated electric utilities. Volumes were weather normalized by PEG Research using econometric demand modelling. The source of the raw volume data is Form EIA 861. The source of the customer data is FERC Form 1.

Figure 2


Unit Cost Trends of Sampled Vertically Integrated Utilities
Annual Growth Rate
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
2002
2004
2005
2006
2007
2008

an allowed ROE of 11%, this would mean a drop in ROE of around 375 basis points before tax adjustments. While lower income taxes would mitigate the earnings impact, we may conclude from this analysis that historical test years would have been inherently non-compensatory for a utility operating under the *typical* business conditions facing VIEUs in recent years. Results would be much worse for utilities facing more pronounced unit cost pressures due, for example, to an accelerated program of replacement capex or a large scale DSM program.

Unit Cost Drivers

Input Prices Our discussion in Section 1.2.1 contained the result that input price inflation, productivity growth, and the trend in average use were key drivers of unit cost growth. We calculated for this report indexes of the inflation in the prices of base rate inputs faced by the sampled VIEUs. The growth rates of the summary input price indexes are weighted averages of the growth rates in indexes of prices for electric utility plant and O&M labor and materials and services. The index for each utility uses as weights the share of each input group in the total cost of the company's base rate inputs.[48] The index for the price of plant was calculated from the trends in bond yields, allowed returns on equity, and the Handy Whitman Construction Cost Index for vertically integrated electric utilities in the applicable region.

Results of our input price research are presented in Table 5 and Figure 3. It can be seen that the prices of base rate inputs averaged 2.76% annual inflation in the 1996-2002 period and 3.65% inflation in the 2003-2008 period --- an increase of 89 basis points. The price acceleration was primarily in materials and services and capital. M&S price inflation averaged 2.08% annually in the 1996-2002 period and 4.31% annually in the 2003-2008 period.

[48] An input price index with cost share weights effectively estimates the impact of price inflation on cost.

Table 5

Trends in Prices of Electric Utility Base Rate Inputs, 1996-2008

Year	Summary Input Price Index		Labor		Materials & Services		Capital	
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
1995	1.000		1.000		1.000		1.000	
1996	1.032	3.2%	1.033	3.2%	1.020	2.0%	1.034	3.3%
1997	1.061	2.7%	1.065	3.1%	1.042	2.1%	1.061	2.7%
1998	1.095	3.2%	1.108	4.0%	1.058	1.6%	1.098	3.4%
1999	1.114	1.7%	1.139	2.7%	1.076	1.6%	1.112	1.2%
2000	1.162	4.2%	1.193	4.6%	1.109	3.0%	1.158	4.1%
2001	1.185	1.9%	1.242	4.0%	1.135	2.4%	1.168	0.8%
2002	1.213	2.3%	1.301	4.6%	1.157	1.9%	1.186	1.5%
2003	1.246	2.7%	1.356	4.2%	1.189	2.7%	1.206	1.7%
2004	1.289	3.4%	1.428	5.1%	1.241	4.3%	1.227	1.7%
2005	1.337	3.7%	1.501	5.0%	1.303	4.9%	1.251	1.9%
2006	1.417	5.8%	1.652	9.6%	1.364	4.6%	1.303	4.1%
2007	1.451	2.3%	1.578	-4.6%	1.421	4.1%	1.352	3.6%
2008	1.510	4.0%	1.629	3.2%	1.498	5.3%	1.396	3.2%
Average Annual Growth Rate								
1996-2008		**3.17%**		**3.76%**		**3.11%**		**2.57%**
1996-2002		**2.76%**		**3.76%**		**2.08%**		**2.43%**
2003-2008		**3.65%**		**3.75%**		**4.31%**		**2.72%**

Sources

Labor: Calculated by PEG Research from BLS Employment Cost Indexes that include pensions and benefits

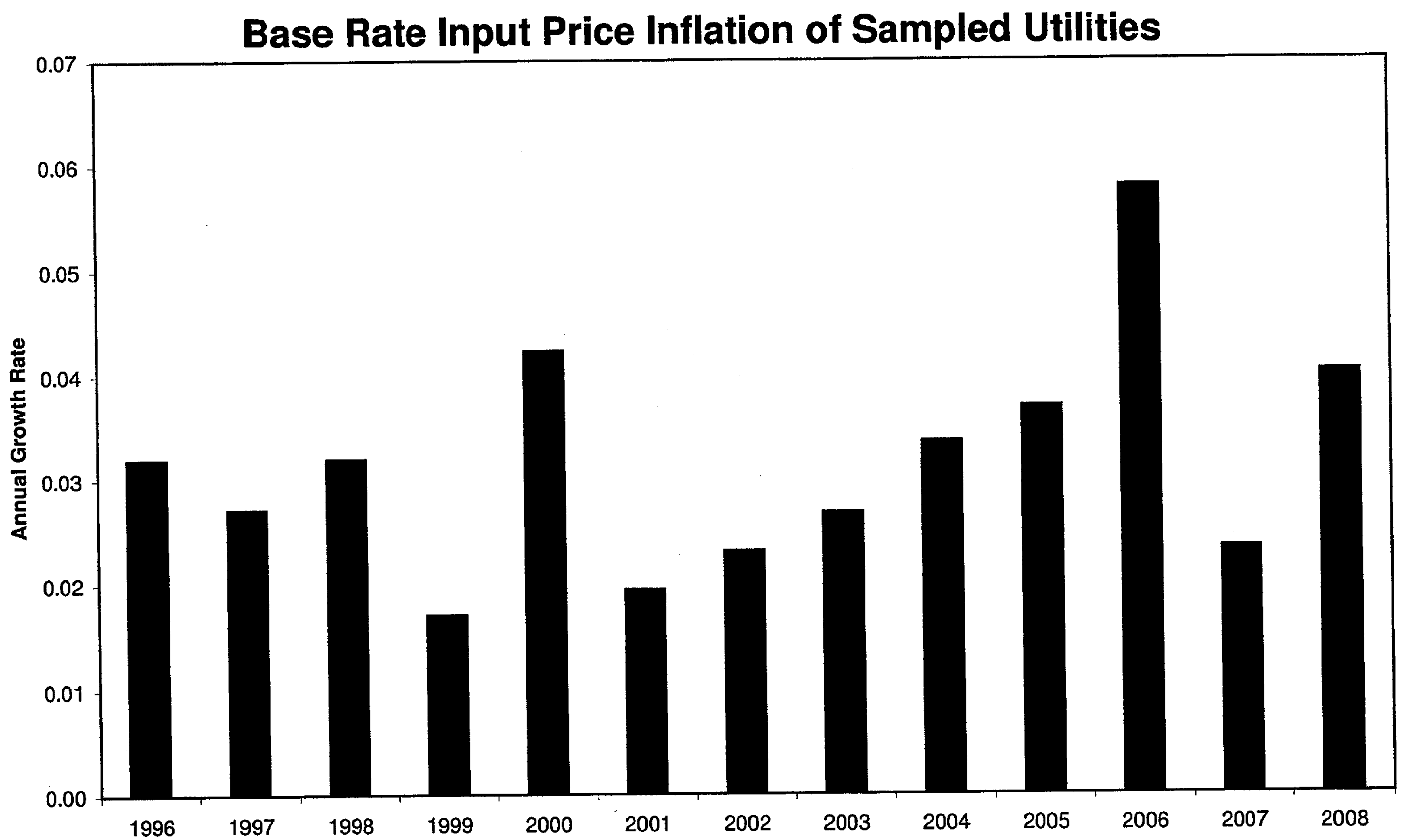
Materials & Services: Calculated by PEG Research using functional cost shares for sampled utilities obtained from FERC Form 1 and detailed electric utility M&S price indexes obtained from Global Insight's *Power Planner.*

Capital: Calculated by PEG Reseach from
- Handy Whitman electric utility construction cost indexes
- Average yields on utility bonds calculated from FERC Form 1 data gathered by SNL Interactive
- Applicable allowed ROEs as reported by Regulatory Research Associates

Summary: Calculated by PEG Research from the labor, M&S, and capital price indexes using vertically integrated electric utility base rate input cost shares drawn from FERC Form 1

FERC Form 1 data gathered by SNL

Figure 3


Base Rate Input Price Inflation of Sampled Utilities
Annual Growth Rate
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008

Plant Additions Large plant additions were noted in Section 1.2.1 to be an important driver of utility productivity growth. Table 6 and Figure 4 describe the trend in real (*i.e.* inflation adjusted) plant additions per customer of the sampled utilities. It can be seen that from 2003 through 2008, real plant additions were 25% higher on average than in the 1995-2002 period.

Average Use In Table 7 and Figure 5 we present information on the trends in weather normalized average use by the residential and commercial customers of a large sample of U.S. electric utilities from 1996 to 2008. The sample included specialized transmission and distribution utilizes as well as VIEUs. It can be seen that the growth rates in average use have tended to fall for both residential and commercial customers since 2002. The trend was more pronounced for residential customers. Growth in normalized average use of power by residential customers averaged 1.09% per year in the 1996-2002 period and 0.43% per year in the 2003-2008 period. Growth in weather-normalized average use by commercial customers averaged 1.04% per year in the 1996-2002 period and 0.74% per year in the 2003-2008 period.

The average use slowdown was especially pronounced in the 2006-2008 period. The normalized average use of residential customers averaged a slight 0.19% annual decline and average use by commercial customers was essentially flat. For this more recent period, we separately calculated trends for utilities in service territories with large DSM programs and the trends for utilities in other territories. The normalized average use by residential customers of utilities operating in territories with large DSM programs declined by a remarkable 0.68% on average.

These results suggest that the typical IOUs may not be able in the future to count on brisk growth in average use by residential and commercial customers to buffer the impact on unit cost growth of input price inflation and increased plant additions. The problem will be considerably more acute in service territories where there are aggressive conservation programs. Forward test years will be particularly uncompensatory where utilities must cope with the consequences for load of aggressive DSM programs.

Table 6

Real Plant Additions Per Customer of Sampled Utilities

	Real Additions to Plant in Service (1995=100)	Number of Customers (1995=100)	Real Additions per Customer (1995=100)
1995	100.00	100.00	100.00
1996	93.26	101.89	91.53
1997	85.99	103.99	82.70
1998	70.50	106.33	66.30
1999	89.82	108.20	83.01
2000	102.31	110.66	92.46
2001	111.46	112.80	98.81
2002	108.46	114.70	94.56
2003	148.32	116.57	127.23
2004	110.42	118.78	92.96
2005	115.52	120.98	95.49
2006	125.04	123.89	100.93
2007	149.51	125.82	118.83
2008	165.19	126.85	130.22
Averages			
1996-2002			87.05
2003-2008			110.94

Sources: Cost and cutomer data from FERC Form 1. Plant additions deflated using applicable regional Handy Whitman electric utility construction cost indexes.

Figure 4

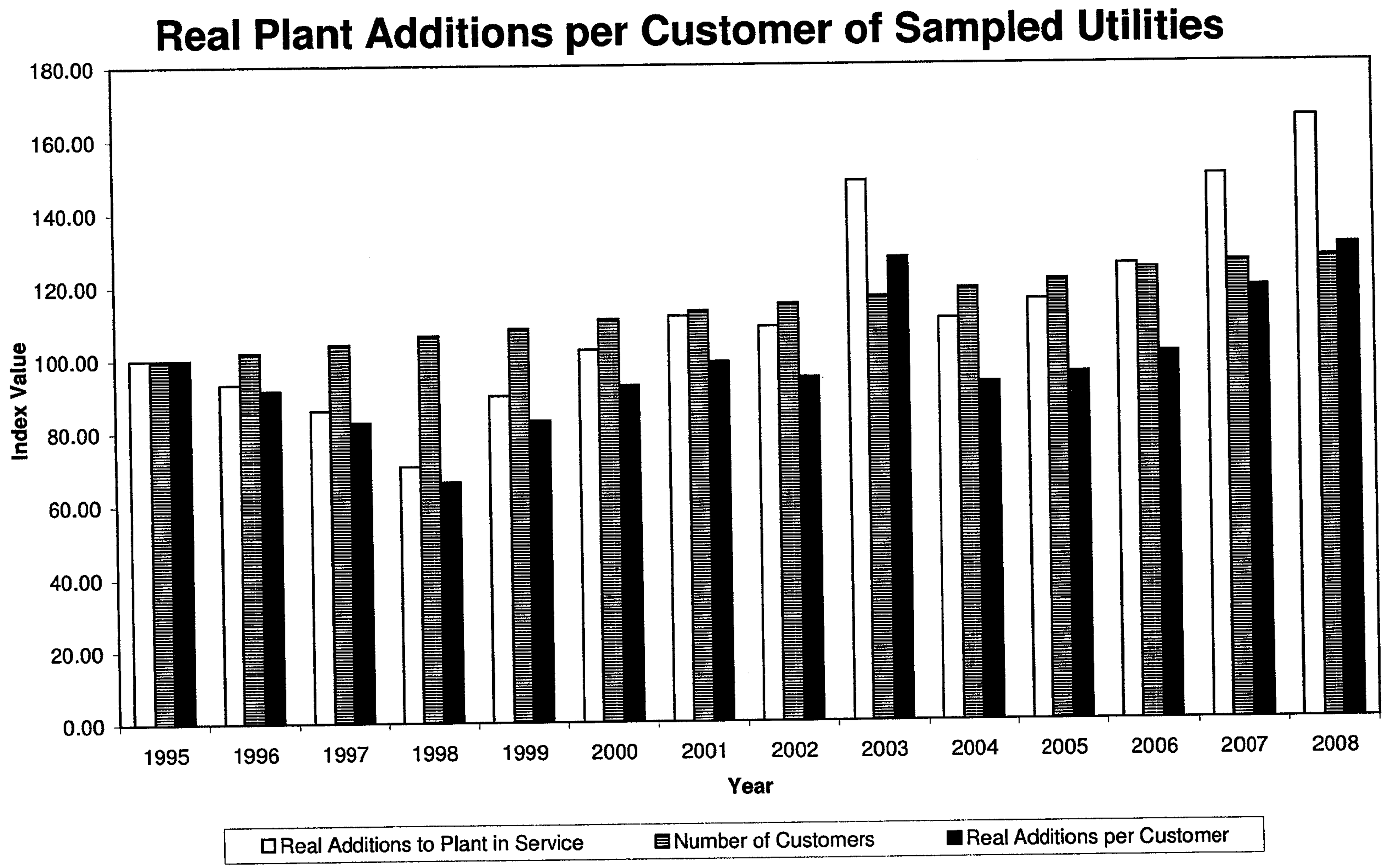

Real Plant Additions per Customer of Sampled Utilities
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Index Value
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
Real Additions to Plant in Service
Number of Customers
Real Additions per Customer

Table 7

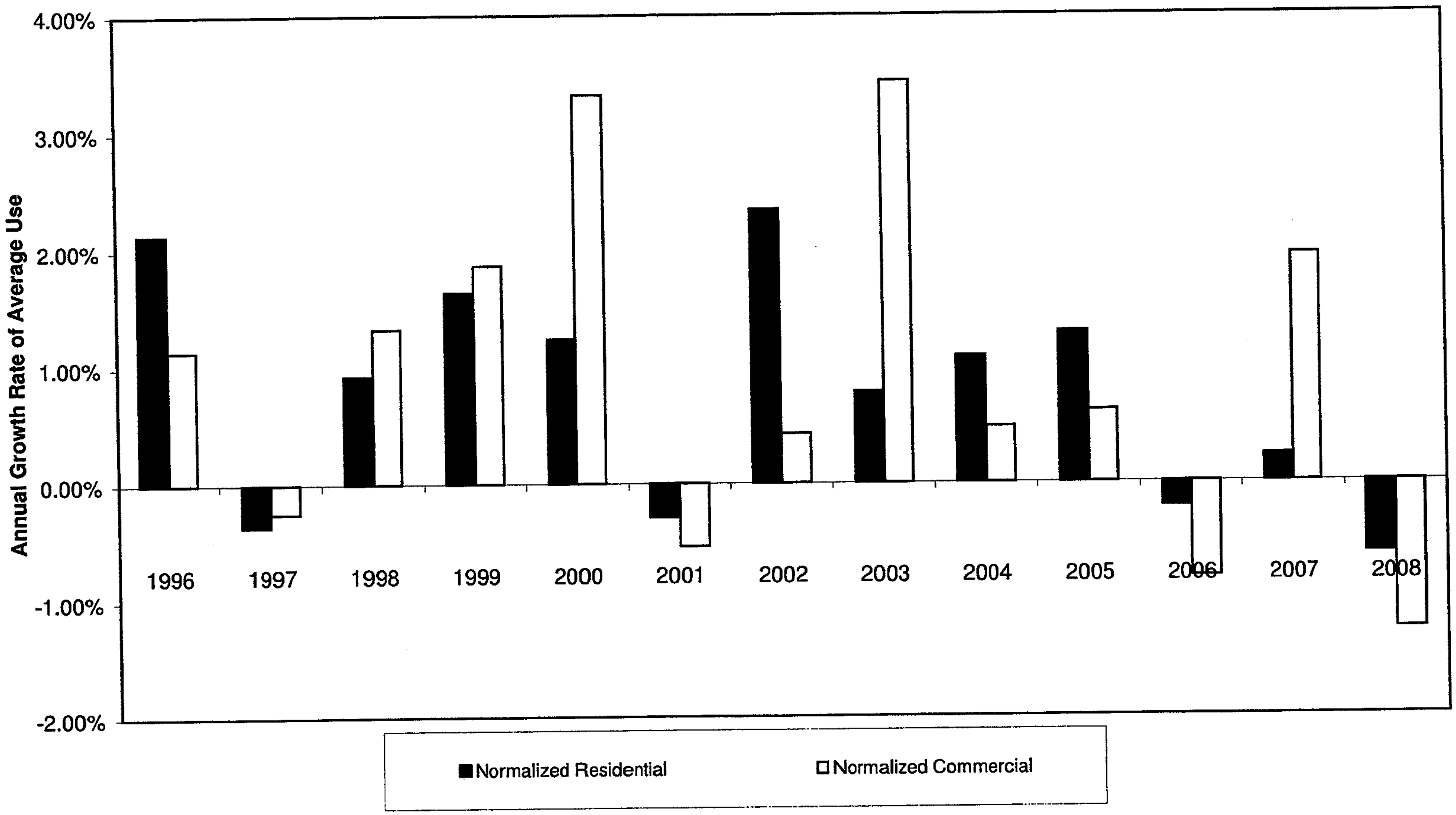
Trends in Average Use by Residential & Commercial Customers of Investor-Owned Electric Utilities

Year	Residential		Commercial	
	Raw	Normalized	Raw	Normalized
1996	1.10%	2.14%	0.68%	1.14%
1997	-2.35%	-0.36%	-0.43%	-0.25%
1998	1.39%	0.93%	1.91%	1.33%
1999	1.66%	1.64%	1.63%	1.87%
2000	2.02%	1.24%	3.20%	3.33%
2001	-0.65%	-0.29%	-0.35%	-0.53%
2002	4.18%	2.35%	0.71%	0.42%
2003	-0.71%	0.78%	2.88%	3.44%
2004	0.03%	1.08%	0.35%	0.48%
2005	4.02%	1.29%	1.24%	0.61%
2006	-2.86%	-0.21%	-1.06%	-0.80%
2007	2.68%	0.23%	2.26%	1.95%
2008	-1.95%	-0.61%	-1.83%	-1.26%
Average Annual Growth Rate				
1996-2008	**0.66%**	**0.79%**	**0.86%**	**0.90%**
1996-2002	**1.05%**	**1.09%**	**1.05%**	**1.04%**
2003-2008	**0.20%**	**0.43%**	**0.64%**	**0.74%**
2006-2008	**-0.71%**	**-0.19%**	**-0.21%**	**-0.04%**
High DSM utilities	**-1.07%**	**-0.68%**	**-0.19%**	**-0.08%**
Other utilities	**-0.54%**	**0.05%**	**-0.22%**	**-0.02%**

Sources: Customer data from FERC Form 1. Volume data from Form EIA 861. Volumes were weather normalized by PEG Research using econometric demand modelling.

Figure 5

Normalized Average Use Trends of Electric IOUs



3.2 How Test Years Affect Credit Quality Metrics

Table 8 presents results for selected credit quality metrics for a large sample of electric utilities. The reported metrics are averages for the 2006-2009 period. The source is *Credit Stats: Electric Utilities—U.S.*, a report appearing in the Global Credit Portal of Standard & Poor's RatingsDirect. We present results for four credit metrics: Standard & Poor's corporate credit rating, the (rate of) return on capital, and two cash flow ratios (EBITDA interest coverage and FFO/Debt).

Cash flow ratios are used by credit analysts to assess a utility's ability to service debt. The cash flow measures are normally calculated as adjustments to net income that add back cash flows that could be used to service debt. FFO (funds from operations), for instance, adds back depreciation and amortization expenses. EBITDA (earnings before interest, taxes, depreciation, and amortization) adds back interest and tax payments as well as depreciation and amortization.

Table 8 reports averages for each of the numerical metrics for utilities that operated under historical, hybrid, and forward test years throughout the 2006-2008 period. There is also an indeterminate category for utilities that are not easily categorized as having operated under one kind of test year during this period.

Caution must be taken in making comparisons inasmuch as these metrics may differ between the sampled utilities due to differences in several other business conditions as well as to any differences in test years. The other relevant business conditions include the ability to rate base construction work in progress, the local severity of the 2008 recession, and whether or not utilities operated under formula rates and/or revenue decoupling. Despite these complications, the samples are large and diverse enough to shed some light on the effect that test years have on credit metrics.

Comparing the results, it can be seen that the values of all four credit metrics were typically much more favorable for the *forward* test year utilities than for the *historical* test year utilities.

- The forward test year utilities had a typical credit rating between BBB+ and A- whereas the historical test year utilities had a typical credit rating between BBB- and BBB.

Table 8

How Credit Metrics of Electric Utilities Differ by Test Year, 2006-2008

Company Name	S&P Corporate Credit Rating	Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Historical Test Years		**7.9**	**4.2**	**18.2**
AEP Texas Central	BBB	6.9	2.8	8.7
AEP Texas North	BBB	8.1	4.9	21.0
Appalachian Power	BBB	6.0	2.9	9.5
Arizona Public Service	BBB-	7.3	4.6	19.3
Black Hills Power	BBB-	9.6	4.8	25.3
Carolina Power & Light	BBB+	11.3	5.9	25.0
CenterPoint Energy Houston Electric	BBB	9.8	6.2	24.4
Central Illinois Light	BBB-	9.5	8.2	29.5
Central Illinois Public Service	BBB-	4.9	3.6	15.7
Central Vermont Public Service	BB+	7.0	2.7	12.8
Commonwealth Edison	BBB-	6.4	3.1	12.1
Duke Energy Carolinas	A-	7.0	6.1	28.5
Duke Energy Indiana	A-	8.0	5.1	21.3
El Paso Electric	BBB	9.4	4.2	18.8
Entergy Gulf States	BBB	7.2	2.8	25.1
Entergy Louisiana	BBB	6.6	3.2	36.3
Entergy Texas	BBB	5.6	2.5	14.0
Interstate Power & Light	BBB+	10.5	5.5	24.4
IPALCO Enterprises (Indianapolis Power & Light)	BB+	13.2	3.4	12.9
Kentucky Power	BBB	6.5	3.5	13.8
MidAmerican Energy	A-	10.7	5.5	22.7
Nevada Power	BB	8.4	2.6	11.1
NSTAR Electric	A+	10.2	7.7	21.6
Oklahoma Gas & Electric	BBB+	10.0	6.4	25.2
Oncor Electric Delivery	BBB+	9.6	4.4	17.9
Public Service Company of Colorado	BBB+	8.1	4.3	19.6
Public Service Company of New Hampshire	BBB	8.4	4.8	13.7
Public Service Company of New Mexico	BB-	3.9	2.3	8.6
Public Service Company of Oklahoma	BBB	4.9	2.7	18.3
Puget Sound Energy	BBB	7.5	3.8	13.7
Sierra Pacific Power	BB	7.4	2.9	12.7
South Carolina Electric & Gas	BBB+	8.3	4.7	21.1
Southern Indiana Gas & Electric	A-	9.5	5.4	22.8
Southwestern Electric Power	BBB	7.4	3.5	15.4
Southwestern Public Service	BBB+	5.3	3.5	12.1
Texas-New Mexico Power	BB-	5.3	3.3	9.5
Tuscon Electric Power	BB+	8.4	3.2	17.9
Westar Energy	BBB-	6.7	3.9	14.8
Western Massachusetts Electric	BBB	5.8	3.7	11.8
Hybrid Test Years		**9.5**	**5.9**	**19.9**
Atlantic City Electric	BBB	9.6	4.4	34.2
Baltimore Gas & Electric	BBB	6.8	4.3	11.1
Cleveland Electric Illuminating	BBB	13.3	4.3	9.2
Cleco Power	BBB	8.3	3.7	10.9
Columbus Southern Power	BBB	13.5	6.5	23.3
Dayton Power & Light	A-	16.3	16.1	42.9
Duke Energy Ohio	A-	5.2	6.3	25.5
Entergy Arkansas	BBB	6.7	5.6	27.7
Idaho Power	BBB	6.6	3.8	10.7
Jersey Central Power & Light	BBB	8.3	8.5	22.9
Metropolitan Edison	BBB	9.3	6.7	12.7
Ohio Edison	BBB	9.4	4.6	14.5
Ohio Power	BBB	8.2	4.3	15.0
PECO Energy	BBB	10.5	7.0	19.5
Pennsylvania Electric	BBB	8.9	5.5	15.8
PPL Electric Utilities	A-	9.5	4.6	18.6
Public Service Electric & Gas	BBB	8.7	4.9	14.9
Toledo Edison	BBB	11.9	5.2	28.0

Table 8, continued

How Credit Metrics of Electric Utilities Differ by Test Year, 2006-2008

Company Name	S&P Corporate Credit Rating	Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Forward Test Years		**9.2**	**5.1**	**21.0**
ALLETE (Minnesota Power)	BBB+	10.8	5.1	19.5
Central Hudson Gas & Electric	A	9.6	4.9	14.9
Central Maine Power	BBB+	8.2	5.3	17.8
Connecticut Light & Power	BBB	6.7	4.3	12.2
Detroit Edison	BBB	8.2	4.9	16.8
Entergy Mississippi	BBB	7.2	4.3	27.1
Florida Power & Light	A	9.9	7.0	30.7
Florida Power Corp.	BBB+	9.9	4.5	19.0
Georgia Power	A	10.1	5.9	22.6
Gulf Power	A	9.7	5.6	19.2
Hawaiian Electric	BBB	7.1	4.4	15.3
Mississippi Power	A	11.6	8.9	35.5
Northern States Power - MN	BBB+	9.4	4.9	22.9
Northern States Power - WI	A-	8.8	5.9	26.6
Pacific Gas & Electric	BBB+	10.7	4.0	23.3
PacifiCorp	A-	7.9	4.0	17.3
Portland General Electric	BBB+	7.9	4.1	19.2
Rochester Gas & Electric	BBB	9.4	3.8	19.4
Southern California Edison	BBB+	11.4	4.0	19.3
Tampa Electric	BBB	9.6	4.5	21.0
Wisconsin Electric Power	A-	6.9	5.4	14.6
Wisconsin Power & Light	A-	10.1	5.0	24.7
Wisconsin Public Service	A-	9.8	5.6	23.8
Indeterminate		**7.8**	**4.3**	**18.1**
Alabama Power	A	9.5	5.7	21.5
Empire District Electric	BBB-	7.3	3.5	15.7
Indiana Michigan Power	BBB	6.7	3.5	15.4
Kansas City Power & Light	BBB	7.9	4.8	19.4
Potomac Electric	BBB	7.4	4.4	20.6
Southwestern Electric Power	BBB	7.4	3.5	15.4
Union Electric	BBB-	8.2	4.4	18.4
All Companies		**8.6**	**4.8**	**19.3**

Source: Standard & Poor's Ratings Direct, *Credit Stats: Electric Utilities - U.S.* August 24, 2009. Financial metrics are averages of the years 2006-2008.

- The forward test year utilities had an average return on capital of 9.2% whereas the historical test year utilities had an average return of 7.9%.
- The forward test year utilities had an average EBITDA/interest coverage of 5.1 whereas the historical test year utilities had an average coverage of 4.2
- The forward test year utilities had an average FFO/debt ratio of 21.0% whereas the historical test year utilities had an average ratio of 18.2%.

Additional insights concerning the effect of forward test years on credit quality can be found in another recent Standard & Poor's report.[49] The study sought to rank state regulatory regimes with respect to their effect on credit quality. Of the fourteen states covered by the study which had well-established forward test year traditions at the time of the study, the author found five to be "more credit supportive", six to be "credit supportive", only two to be "less credit supportive", and none to be "least credit supportive". In contrast, of the seventeen states covered by the study that had well-established historical test year conditions, only three were categorized as "more credit supportive", seven were categorized as "credit supportive", six were categorized as "less credit supportive" and one was categorized as "least credit supportive".

3.3 Incentive Impact of Forward Test Years

In Section 1.2.4 we noted that the incentive impact of forward test years has been an issue in some proceedings. We argued, based on our experience in the field of incentive regulation, that the incentive impact of forward and historical test years should be similar on balance. To test the hypothesis that the choice of a test year has no impact on operating efficiency, PEG Research measured the trends in the O&M expenses of a large group of VIEUs over the 1996-2008 sample period. O&M expenses are a better focus than the total cost of base rate inputs in such a study because some utilities had greater needs than others for major plant additions and these needs had little to do with the kind of test year in a jurisdiction. Differences in cost growth are due in part to differences in output growth, so we divided O&M expenses by three alternative output metrics: generation volumes, generation capacity, and the number of customers served. We calculated how the trends in the three cost metrics differed for utilities operating under three kinds of test years: historical, hybrid, and

[49] Todd Shipman, *Assessing U.S. Utility Regulatory Environments*, Standard & Poor's Ratings Direct, November 2008.

forward. If forward test years weaken operating efficiency, we would expect the growth in the cost metrics to be higher on average for the forward test year utilities.

Results of this exercise are reported in Table 9. It can be seen that, using all three cost metrics, the cost trends of the forward test year utilities were similar to --- and a little slower than --- those of the historical test year utilities and of the full utility sample. These results are consistent with the notion that there is no significant difference in the incentives to contain cost that are generated by future and historical test years.

Table 9

Trends in Unit Non-Fuel O&M Expenses by Test Year, 1996-2008

	Test Year Type			
	Historic	Partial	Forward	All
Cost/Customer	2.1%	2.0%	1.9%	2.2%
Cost/Generation Volume	2.2%	3.0%	1.4%	2.3%
Cost/Generation Capacity	1.9%	3.2%	1.3%	1.9%

Source: Federal Energy Regulatory Commission (FERC) Form 1 and Form EIA-876 data gathered by SNL Financial.

4. CONCLUDING REMARKS

Having established in some detail in the chapters above the financial stresses imposed on U.S. electric utilities by historical test years today, we provide in this chapter some concluding remarks on action plans for regulators who wish to move forward with sensible remedies.

4.1 Sensible First Steps

In states where regulators are interested in experimenting with forward test years but not yet prepared to "make the plunge" to large scale adoption, our discussion has identified a number of cautious first steps down the road that limit the risk of bad outcomes but permit the regulatory community to learn more about FTY pros and cons.

- Allow a forward test year on a trial basis for one interested utility.
- Allow forward test years on an occasional basis when a utility makes a convincing case that rising unit costs make historical test years unjust and unreasonable. A ruling on the test year issue can precede the preparation of a rate case, as in Utah.
- Borrow a few of the methods used in FTY rate cases to make additional adjustments to *historical* test year costs and billing determinants. For example, HTY O&M expenses and/or plant addition costs can be adjusted for forecasts of price inflation prepared by respected independent agencies. Residential and commercial delivery volumes can be adjusted for recent average use trends. Special adjustments can be made for looming major plant additions.
- Try current FTYs, which involve forecasts only one year into the future. Current test years can be combined with interim rate increases at the outset a rate case which are subject to true up when new rates are ultimately approved. The combination of current test years and interim rates is a salient option because it eliminates regulatory lag without a two year forecast.

4.2 Alternative Remedies for Test Year Attrition

In states where regulators aren't ready to abandon historical test years but are sympathetic to the attrition problems that they sometimes cause, a variety of alternative measures are available to relieve the financial attrition that can result from using historical test years in a rising unit cost environment.

1. HTY calculations can incorporate the full array of normalization, annualization, and known and measurable change adjustments that are used in other jurisdictions.
2. Utilities can be permitted to implement interim rate increases. Interim rates can effectively reduce regulatory lag by a year. States that permit interim rates include HI, IA, MI, MO, NH, OK, TX, VA, and WI.
3. Capital spending trackers can ensure timely commencement of the recovery of costs of plant additions, without rate cases, when assets become used and useful. Trackers can be designed to maintain incentives for good capital cost management and timely project completion. Monitoring by PEG Research reveals that capital spending trackers have been approved for use by energy utilities in AR, CA, FL, GA, IA, ID, IL, IN, KS, KY, MD, ME, MN, MO, NJ, NY, OH, OK, OR, PA, TX, VA, and WI.
4. The inclusion of CWIP in rate base improves cash flow and reduces future rate shocks. This practice also reduces the losses that a utility experiences making large plant additions under historical test year rates. Monitoring by the Edison Electric Institute has found that states that have recently allowed inclusion of CWIP in rate base include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.
5. Cost trackers can also adjust rates automatically to ensure timely recovery of O&M expenses that are unusually volatile and/or expected to rise rapidly. Expenses that are often recovered using trackers include those for pensions and benefits, uncollectible bills, and DSM.
6. Several methods have been established to compensate utilities for slowing growth in average use.
   - Lost revenue adjustment mechanisms (a/k/a lost margin trackers) restore margins that are estimated to have been lost because of utility conservation programs. These are currently used by electric utilities in CT, IN, KY, OH, NC, and SC.

- Decoupling true-up plans help base rate revenue track revenue requirements more closely and can thereby restore lost margins that result from slow growth in average use resulting from a wider variety of sources, including conservation programs administered by independent agencies. Such plans are currently used by electric utilities in CA, CT, DC, HI, ID, MA, MD, MI, NY, OR, VT, and WI. They are used by gas utilities in several additional states (*e.g.* AR, CO, IN, MN, NJ, NC, UT, VA, WA, and WY).
- Higher customer charges are also effective in reducing attrition from declining average use. Straight fixed variable pricing, which recovers *all* fixed costs using fixed charges, is used by gas utilities in GA, MO, OH, OK, and ND.

7. The duration of rate cases can be limited. A reasonable cap is the average length of cases in the United States, which is currently between nine and ten months.[50]
8. Multiyear rate plans can give utilities rate escalation between rate cases for inflation and other business conditions that drive cost growth. Such plans typically have a duration of three to five years, and terms of seven to ten years have been approved. Even if an historical test year makes the initial rates under such plans non-compensatory, it would only happen once in a multiyear period. Utilities would have several years to recoup their losses through superior productivity growth --- and an incentive to do so. North American jurisdictions where multiyear rate plans are common include CA, ME, MA, NY, OH, and VT in the United States and Alberta, British Columbia, and Ontario in Canada. This approach to ratemaking is more the rule than the exception overseas.

[50] See *EEI 2007 Financial Review*, p. 36.

APPENDIX: UNIT COST LOGIC

To better understand the conditions that can cause historical test year rates to produce earnings attrition, suppose that year t is a rate year (a year when new rates take effect) and that the utility is underearning with its newly implemented HTY rates. The cost of base rate inputs then exceeds base rate revenue and the ratio of cost to revenue is positive.

$$Cost_t / Revenue_t > 0.$$

To simplify the story, suppose next that the utility has only one service and the base rate for that service is gathered exclusively from a volumetric charge. In the historical test year, the revenue requirement is then the product of a price (P_{t-2}) and a volume (V_{t-2}) and this is set equal to the allowed cost of service

$$P_{t-2} \times V_{t-2} = Cost_{t-2}$$

so that

$$P_{t-2} = Cost_{t-2} / V_{t-2} = \text{Unit } Cost_{t-2}.$$

The rate equals the cost per kWh of sales, which we may call the *unit* cost of service in the historical test year.

Revenue in the rate year is the product of this same price, which reflects *historical* business conditions, and the *contemporary* sales volume. The ratio of cost to revenue may then be restated as

$$\begin{aligned} Cost_t / Revenue_t &= Cost_t / (P_{t-2} \times V_t) \\ &= Cost_t / [(Cost_{t-2} / V_{t-2}) \times V_t] \\ &= (Cost_t / V_t) / (Cost_{t-2} / V_{t-2}) \\ &= \text{Unit } Cost_t / \text{Unit } Cost_{t-2}. \qquad [A1] \end{aligned}$$

An historical test year rate is thus non-compensatory if the utility's unit cost is higher in the rate year than it was two years ago in the test year. Growth in the unit cost of the utility is thus the fundamental reason for earnings attrition. Note also that

$$\text{Unit } Cost_t / \text{Unit } Cost_{t-2} = (Cost_t / Cost_{t-2}) / (V_t / V_{t-2}). \qquad [A2]$$

Unit cost thus grows between the test year and the rate year if cost grows more rapidly than the sales volume. Growth in the sales volume therefore matters as well as cost growth in determining a utility's unit cost trend. Moreover, the ability of historical test year rates to avoid under or, for that matter, over earning depends on the stability of the relationship between cost and billing determinants.

The key result that historical test years are non-compensatory when unit cost is rising extends to the real world situation in which a utility provides multiple services, each with several charges. In this situation the ratio of the total delivery volume in [A2] is replaced by a weighted average of the ratios for all billing determinants.[51]

[51] The weight for each individual billing determinant is its share of the total base rate revenue.

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Power by Association

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Prepared by: Pacific Economics Group Research LLC

Prepared for: Edison Electric Institute

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Prepared by:
Pacific Economics Group Research LLC

Mark Newton Lowry, PhD

Matthew Makos

Gentry Johnson

Prepared for:
Edison Electric Institute

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Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Phone: 202-508-5000
Web site: www.eei.org

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I. Introduction

Many utilities are experiencing the problem of regulatory lag today. They are struggling with a tendency of costs to grow more rapidly than the delivery volumes and other billing determinants that cause revenue growth. Some utilities need major generation or transmission plant additions. Others are engaged in accelerated programs to modernize distribution plant or install advanced metering infrastructure ("AMI"). Growth in the volume of utility services used by a typical customer ("average use") once helped to finance plant additions because it bolstered revenue more than cost. However, growth in average use has slowed with a weak economy and increased energy efficiency. Traditional approaches to regulation can fail to provide timely rate relief under these conditions. The result can be chronic financial attrition that increases risk and can discourage needed investments.

Alternatives to traditional regulation have been developed which reduce regulatory lag. These include cost trackers, the inclusion of construction work in progress ("CWIP") in rate base, multiyear rate and revenue caps, revenue decoupling, formula rates, and forward test years. This review briefly explains these options and provides a summary of precedents for electric and natural gas utilities. A summary of states that currently use these approaches is featured in Table 1. Natural gas precedents are included because of their relevance to "wires only" electric power distributors.

Table 1

Innovations to Reduce Regulatory Lag: An Overview of Current Precedents

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Cap[2]	Multiyear Revenue Cap[3]	Revenue Decoupling: Decoupling True Up Plans	Revenue Decoupling: Lost Revenue Adjustment Mechanisms	Revenue Decoupling: Fixed Variable Retail Pricing	Retail Formula Rate Plans	Forward Test Years
Alabama								Yes	Yes
Arizona									
Arkansas	Yes				Yes (gas only)				
California	Yes		Yes (electric only)	Yes	Yes				Yes
Colorado	Yes (electric only)	Yes			Yes (gas only)	Yes (electric only)			Pending
Connecticut					Yes (electric only)	Yes (gas only)	Yes (electric only)		Yes
Delaware							Pending		
District of Columbia					Yes (electric only)				
Florida	Yes (electric only)	Yes					Yes (gas only)		Yes
Georgia	Yes	Yes	Yes (electric only)				Yes (gas only)		Yes
Hawaii	Yes (electric only)			Yes (electric only)	Yes (electric only)				Yes
Idaho					Yes (electric only)				
Illinois	Yes (gas only)				Yes (gas only)		Yes (gas only)		Yes
Indiana	Yes	Yes			Yes (gas only)	Yes (electric only)			
Iowa	Yes (electric only)								
Kansas	Yes	Pending							
Kentucky	Yes					Yes			Yes
Louisiana	Yes (electric only)	Yes						Yes	
Maine	Yes (electric only)		Yes						Yes
Maryland		Yes			Yes				
Massachusetts	Yes		Yes		Yes	Yes			
Michigan		Pending			Yes				Yes

State	Capex Cost Tracker	CWIP In Rate Base[1]	Multiyear Rate Cap[2]	Multiyear Revenue Cap[3]	Revenue Decoupling: Decoupling True Up Plans	Revenue Decoupling: Lost Revenue Adjustment Mechanisms	Revenue Decoupling: Fixed Variable Retail Pricing	Retail Formula Rate Plans	Forward Test Years
Minnesota	Yes (electric only)	Yes			Yes (gas only)				Yes
Mississippi	Yes (electric only)	Yes					Yes (electric only)	Yes	Yes
Missouri	Yes (gas only)						Yes (gas only)		
Montana					Yes (electric only)				
Nebraska									
Nevada					Yes (gas only)	Yes (electric only)			
New Hampshire									
New Jersey	Yes				Yes (gas only)				
New Mexico		Pending							Pending
New York	Yes			Yes	Yes				Yes
North Carolina		Yes			Yes (gas only)	Yes (electric only)			
North Dakota		Pending					Yes (gas only)		Yes
Ohio	Yes		Yes (electric only)			Yes (electric only)	Yes (gas only)		
Oklahoma	Yes (electric only)	Pending				Yes (electric only)	Yes (gas only)	Yes (gas only)	
Oregon	Yes				Yes	Yes (gas only)			Yes
Pennsylvania	Yes (electric only)								
Rhode Island					Pending				Yes
South Carolina		Yes				Yes (electric only)		Yes (gas only)	
South Dakota		Pending							
Tennessee					Yes (gas only)				Yes
Texas	Yes (electric only)	Yes						Yes (gas only)	
Utah	Yes (gas only)				Yes (gas only)				Yes
Vermont	Yes (electric only)			Yes	Yes				
Virginia	Yes (electric only)	Yes			Yes (gas only)				
Washington					Yes (gas only)				
West Virginia		Yes							
Wisconsin		Yes			Yes				Yes
Wyoming					Yes (gas only)	Yes (electric only)			Yes (electric only)

[1] This column pertains only to electric utilities.
[2] This column excludes plans involving rate freezes.
[3] Revenue caps are also denoted as decoupling true up plans. However, many decoupling true up plans do not involve multiyear revenue caps because they do not have broad-based revenue adjustment mechanisms.

II. Cost Trackers and CWIP in Rate Base

Trackers are used in various situations where it is less practical to rely on general rate cases to adjust rates for particular changes in business conditions. For example, the energy costs of utilities are usually recovered via cost trackers because their volatility and substantial size would otherwise lead to frequent general rate cases and/or elevated earnings risk. Other volatile costs that are sometimes recovered using trackers include those for pensions and uncollectible bills.

Trackers are also used for recovering costs that are rapidly rising irrespective of their volatility. This can facilitate investment, and reduce risk and the frequency of rate cases. Slow growth in average use reduces concern about overearning because the growth in billing determinants is less likely to exceed the growth in cost that is not recovered by trackers. Examples of utility costs that are tracked because of their rapid growth include those for health care, demand side management ("DSM"), and surges in plant additions.

Trackers for the annual cost of plant additions are sometimes called capital expenditure ("capex") trackers. Plant additions can surge for several reasons. Utilities engaged in transmission and distribution occasionally have major plant additions that increase the rate base substantially. Base load generation is a common source of major plant additions for vertically integrated electric utilities. Base load power plants can take years to construct. An allowance in rates for funds used during construction is traditionally not permitted until assets are used and useful. This involves extra interest expenses and produces rate "shock" when the value of the plant is finally added to the rate base. The delay in receiving a return on investment increases utility risk, and this further increases the cost of construction that customers ultimately pay. Many commissions address these problems by including costs of construction work in progress ("CWIP") in the rate base so that a return on investment can start sooner. Capex trackers are often used in lieu of rate cases to recover the annual return on CWIP.

The cost of replacing aging distribution and metering facilities is sometimes recovered using capex trackers for a somewhat different set of reasons. The annual expenditure may not be as large as that for new or repowered baseload generation, and replacements in a particular neighborhood don't usually take several years. However, the annual expenditure can still be sizable and, unlike new generation or customer connections, doesn't naturally trigger new revenue when facilities become used and useful. A tracker for the accumulating annual cost of the new investment can help a company modernize its grid and improve its services without frequent rate cases.

Capex trackers have varied treatments of cost. Plant addition budgets are often set in advance. Some trackers permit conventional prudence review of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (*e.g.* 50-50) between the utility and its customers. Trackers for AMI capex may involve supplemental award/penalty mechanisms that encourage effective use of the new metering systems.

Recent capex tracker precedents are shown in Figure 1 and Table 2. It can be seen that there are numerous precedents. Trackers for gas utilities often focus on the cost of replacing old cast iron and bare steel mains. Recent electric utility precedents for CWIP in rate base are shown in Table 3 and Figure 2. It can be seen that most involve investments in generating plant.

Figure 1: Recent Capex Tracker Precedents by State

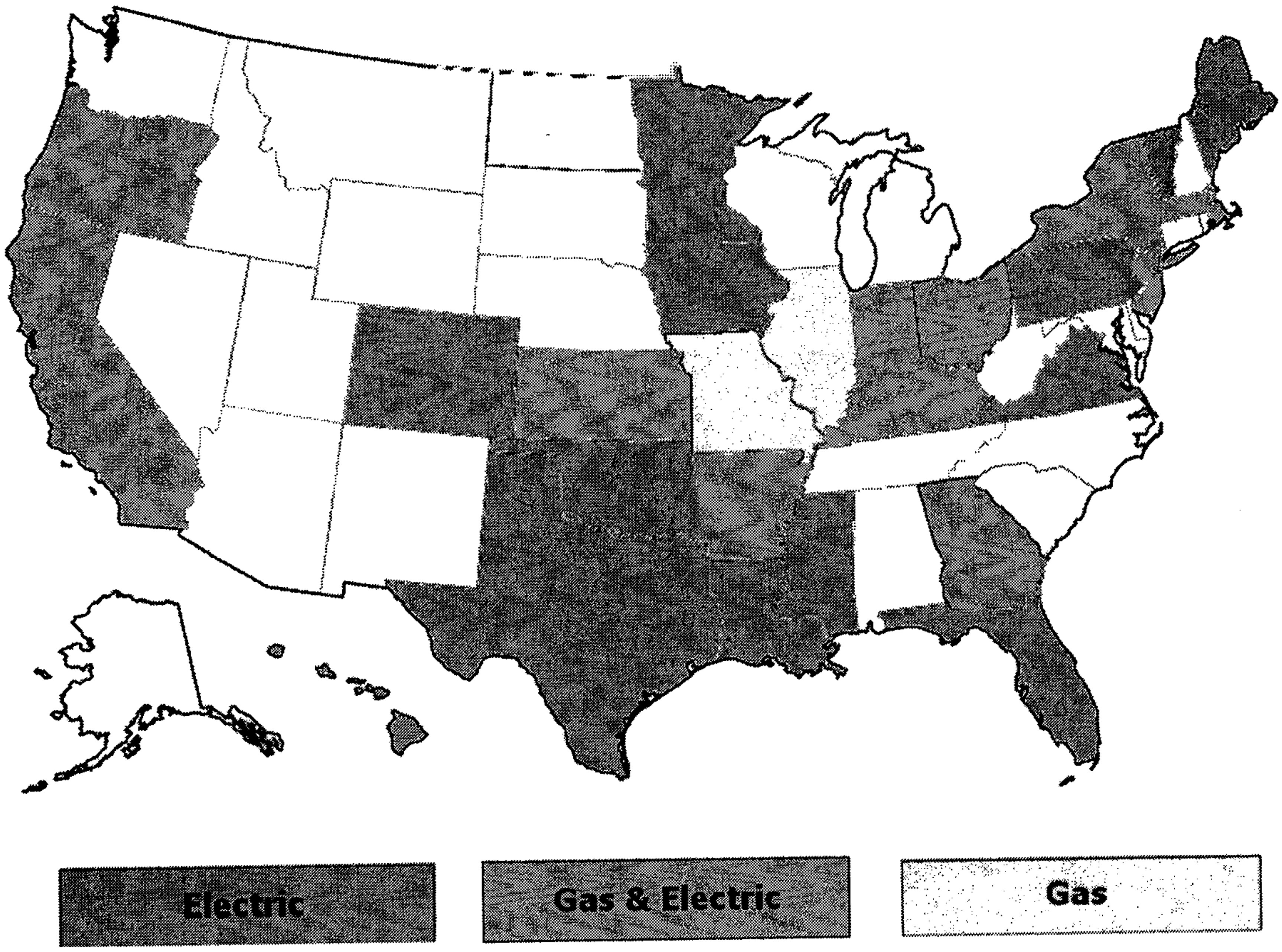


Table 2: Recent Capex Tracker Precedents

Jurisdiction	Company Name	Tracker Name	Eligible Investments	Case Reference
AR	SWEPCO	Generation Recovery Rider	Financing costs and construction expenditures for Turk and Stall generation plants	Docket No 09-008-U (November 2009)
AR	CenterPoint Energy Arkla	Main Replacement Rider	Accelerated replacement of cast iron and bare steel mains and services	Docket 06-161-U (October 2007)
CA	All utilities	Backstop Cost Recovery Mechanism	Construction of Tx facilities that facilitate RPS goals & not approved for recovery in Tx rates by the FERC	Decision No. 06-06-034 (June 2006)
CA	Pacific Gas & Electric	Balancing Accounts	AMI including associated computer systems and software	Decision 06-07-027 (July 2006)
CA	Pacific Gas & Electric	Cornerstone Improvement Project Balancing Account	Capital and O&M expenses to improve the reliability of the electric distribution system	Decision 10-06-048 (June 2010)
CA	San Diego Gas & Electric	Advanced Metering Infrastructure Balancing Account	AMI including information technology, business and organizational readiness, field deployment, systems integration and program management and organization	Decision 07-04-043 (April 2007)
CA	San Diego Gas & Electric	Steam Generator Replacement Project	Steam generator replacement for San Onofre Nuclear Generating Stations	Decision 06-11-026 (November 2006)
CA	Southern California Edison	Steam Generator Replacement Project	Steam generator replacement for San Onofre Nuclear Generating Stations	Decision 05-12-040 (December 2005)
CA	Southern California Edison	Advanced Metering Infrastructure Balancing Account	Predeployment costs associated with the Advanced Metering Infrastructure Project	Decision No. 06-12-026 (December 2006)
CA	Southern California Edison	SmartConnect Balancing Account	Deployment costs associated with the Advanced Metering Infrastructure Project	Decision No. 08-09-039 (September 2008)
CA	Southern California Edison	Backstop Cost Recovery Mechanism	Construction of the Vincent-Tehachapi Tx facilities that facilitate RPS goals & not approved for recovery in Tx rates by the FERC	Decision No 07-03-045 (March 2007)
CO	Public Service Company of Colorado	Transmission Cost Adjustment	Transmission investment costs not recovered through the company's base rates	Docket No 08S-520E, Decision No C09-595 (June 2009)
FL	Florida Power and Light	Environmental Cost Recovery Clause	Renewable power generation plant	Docket No. 080281-EI (August 2008)
FL	Florida Power and Light	Capacity Cost Recovery Clause	Nuclear power plant	Docket No. 090009-EI (November 2009)
FL	Florida Power and Light	Nuclear Cost Recovery Clause	Construction of new nuclear generation	Docket No 080009-EI (September 2008)
FL	Progress Energy Florida	Capacity Cost Recovery Clause	Nuclear power plant	Docket No. 090009-EI (November 2009)
FL	Progress Energy Florida	Nuclear Cost Recovery Clause	Nuclear generation	Docket No. 080009-EI (September 2008)
FL	Progress Energy Florida	Environmental Cost Recovery Clause	Renewable power generation plant or purchases from such plants	Docket No 050078-EI (September 2005)
GA	Atmos Energy	Pipe Replacement Surcharge	Replace cast iron and bare steel pipe	Docket No. 12509-U (December 2000)
GA	Atlanta Gas Light	Strategic Infrastructure Development and Enhancement Program	Infrastructure improvements that sustain reliability and operational flexibility	Docket No. 8516-U (October 2009)
GA	Georgia Power Company	Environmental Compliance Cost Recovery	Cost related to environmental compliance	Docket No. 25060-U (December 2007)
HI	Hawaiian Electric Company	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure projects designed to encourage third party renewable developers and maintain reliability	Docket No 2007-0416 (December 2009)
IA	MidAmerican Energy	Cooper Tracking Mechanism	Nuclear plant additions	Docket APP-96-1 (June 1997), Docket No. TF-02-154 (APP-96-1, RPU-96-8) (May 2003)
IL	Peoples Gas Light & Coke	Rider Incremental Cost Recovery	Replacement of cast iron and bare steel pipe	Case No. 09-0167 (January 2010)
IN	Duke Energy Indiana	Qualified Pollution Control Property	Investment for its Nitrogen Oxide reduction compliance plan	Cause No. 41744 (February 2001)
IN	Duke Energy Indiana	Integrated Coal Gasification Combined Cycle Generating Facility Cost Recovery Adjustment	Integrated gasification combined cycle generating plant	Docket No. 43114 (November 2007)
IN	Duke Energy Indiana	Clean Coal Operating Cost Revenue Adjustment Rider	Qualified pollution control property	Cause No. 42061 ECR 7 (June 2006)
IN	Indiana Gas Company a.k.a. Vectren North	Distribution Reliability Adjustment	Accelerated replacement of cast iron and bare steel mains and services	Docket No. 43298 (Feburary 2008)
IN	Southern Indiana Gas and Electric a.k.a. Vectren South	Distribution Reliability Adjustment	Accelerated replacement of cast iron and bare steel mains and services	Docket No. 43112 (August 2007)
KS	Atmos Energy	Gas System Reliability Surcharge	Infrastructure system replacements	Docket No 10-ATMG-133-TAR (December 2009)
KS	Black Hills Energy (Aquila)	Gas System Reliability Surcharge	Infrastructure system replacements	Docket No. 07-AQLG-431-RTS (May 2007)
KS	Kansas Gas Service	Gas System Reliability Surcharge	Infrastructure system replacements	Docket 10-KGSG-155-TAR (December 2009)
KS	Midwest Energy	Gas System Reliability Surcharge	Infrastructure system replacements	Docket 09-MDWE-722-TAR (May 2009)
KS	Westar Energy Inc	Environmental Cost Recovery Rider	Equipment directly tied to enviromental improvement	Docket No. 05-WSEE-981-RTS (October 2005)
KY	Atmos Energy	Pipe Replacement Program Rider	Replacement of bare steel service lines, curb valves, meter loops, and mandated relocates	Docket No 2009-00354 (May 2010)
KY	Columbia Gas	Advanced Main Replacement Rider	Accelerated replacement of cast iron and bare steel mains and services	Docket No 2009-00141 (September 2009)
KY	Delta Natural Gas	Pipe Replacement Program Surcharge	Accelerated replacement of bare steel pipe, service lines, curb valves, meter loops, and mandated pipe relocations	Case No. 2010-00116 (October 2010)
KY	Kentucky Power	Environmental Cost Recovery Surcharge	Pollution control facilities	Docket No. 2002-00169 (March 2003)
KY	Union Light, Heat and Power (Duke Energy Kentucky)	Advanced Main Replacement Rider	Accelerated replacement of cast iron and bare steel mains and services	Docket No 2001-00092 (January 2002)
LA	Cleco Power	Infrastructure and Incremental Costs Recovery	Power plants, Acadiana load pocket transmission, environmental control facilities, other projects to be determined	Docket U-30689 (October 2010)

Table 2 (continued)

Jurisdiction	Company Name	Tracker Name	Eligible Investments	Case Reference
MA	Bay State Gas	Targeted Infrastructure Recovery Factor	Incremental replacement above test year expenditures of unprotected steel mains and services	DPU 09-30
MA	National Grid (Boston-Essex Gas and Colonial Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel, cast iron, and wrought iron mains services, meters, meter installations, and house regulators	DPU 10-55
MA	National Grid (Massachusetts Electric & Nantucket Electric)	Net CapEx Adjustment	Distribution capital investment including customer additions and reliability projects	DPU 09-39
MA	National Grid (Massachusetts Electric & Nantucket Electric)	Smart Grid Distribution Adjustment Factor	Smart grid pilot program	DPU 09-32
MA	NSTAR	NA	Smart grid pilot program	DPU-09-33
MN	Northern States Power (Xcel Energy)	Mercury Cost Recovery Rider	Investments made to comply with the Mercury Emissions Reduction Act of 2006	Docket No. M-09-847 (November 2009)
ME	Central Maine Power	NA	AMI	Docket No. 2007-215(II) (Feburary 2010)
MO	Atmos Energy	Infrastructure System Replacement Surcharge	Mains, valves, service lines, regulator stations, vaults, other pipeline components that have worn out, need upgrading due to safety requirements or were relocated due to public construction works	Docket No GO-2009-0046 (October 2008)
MO	Laclede Gas	Infrastructure System Replacement Surcharge	Mains, valves, service lines, regulator stations, vaults, other pipeline components that have worn out, need upgrading due to safety requirements or were relocated due to public construction works	Docket No. GR-2007-0208 (July 2007)
MO	Missouri Gas Energy	Infrastructure System Replacement Surcharge	Natural gas line replacements and relocations	Docket No. GR-2009-0355 (Feburary 2010)
MS	Mississippi Power	Environmental Compliance Overview Plan Rate	Environmental equipments and facilities at various generation plants	Docket No. 92-UA-0058 and 92-UN-0059 (July 1992)
NJ	Atlantic City Electric	Infrastructure Investment Surcharge	Investments to replace, reinforce and expand infrastructure	Docket No. EO09010049 and GO09010054 (April 2009)
NJ	Elizabethtown Gas	Cost Recovery Rider	Projects to enhance reliability and reinforce infrastructure	Docket No. GO09010053 (April 2009)
NJ	New Jersey Natural Gas	Accelerated Infrastructure Projects	Replace bare steel mains, reinforce distribution system & transmission mains	Docket No. GO09010052 and GR07110889 (April 2009)
NJ	Public Service Electric and Gas	Capital Infrastructure Investment Program	Electric reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Docket No. GO09010050 (April 2009)
NJ	Public Service Electric and Gas	Solar Generation Investment Program	Solar generation construction including small distributed solar systems on power poles	Docket No. EO09020125 (August 2009)
NJ	South Jersey Gas	Capital Investment Recovery Tracker	Bare steel replacement, expand key distribution mains for reliability	Docket No GO09010051 (April 2009)
NY	Consolidated Edison	Monthly Adjustment Clause	AMI, SCADA, undergrounding	Case 09-E-0310 (October 2010)
NY	Corning Natural Gas	Delivery Rate Adjustment	Capital additions & proprety taxes that are incremental to the amounts included in the Rate Year rates	Docket No 08-G-1137 (March 2009)
NY	National Grid NY (formerly Brooklyn Union Gas and Long Island Lighting)	Capital Tracker	Keyspan Energy Delivery New York's and Long Island's differences between actual construction expenditures required by the City or State and the projected levels set forth in the Joint Proposal	Docket No. 06-M-0878 (September 2007)
OH	Cleveland Electric Illuminating	Delivery Service Improvement Rider	Distribution reliability enhancements	0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Cleveland Electric Illuminating	Rider AMI	Ohio Site Deployment Pilot (3 year AMI pilot)	Case No. 07-551-EL-AIR, 09-1820-EL-ATA, and 10-388-EL-SSO
OH	Cleveland Electric Illuminating	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No 10-388-EL-SSO (August 2010)
OH	Columbia Gas of Ohio	Infrastructure Replacement Program Rider	Replacement of cast iron and bare steel mains & services, replace faulty customer-owned services, install AMI over 5 years	Case No. 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case No. 09-1036-GA-RDR (April 2010)
OH	Columbus Southern Power	GridSMART Rider (Phase I)	Install smart grid including AMI, Distribution Automation (DA) that allows the identification and isolation of faulted distribution lines & Home Area Network (HAN)	Case No 08-917-EL-SSO and 08 918-EL-SSO (March 2009)
OH	Dayton Power and Light	Environmental Investment Rider	Environmental plant additions	Case No. 05-276-EL-AIR (December 2005)
OH	East Ohio Gas d/b/a Dominion East Ohio	Pipeline Infrastructure Replacement Rider	Pipelines & faulty risers replacements	Case No. 09-458-GA-RDR (December 2009)
OH	East Ohio Gas d/b/a Dominion East Ohio	Automated Meter Reading Charge	Installation of automated meter reading technology	Case No. 07-0829-GA-AIR, 07-0830-GA-ALT, 07-0831-GA-AAM, 08-0169-GA-ALT, and 06 1453-GA-UNC (October 2008); Case No. 09-38-GA-UNC (May 2009); Case No. 09-1375-GA-RDR (May 2010)
OH	Duke Energy Ohio	Accelerated Main Replacement Program Rider	Replacement of bare steel and cast iron mains and services, later extended to customer risers	Case No. 01-1228-GA-AIR, and 01-1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Advanced Utility Rider	AMI	Case No. 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)

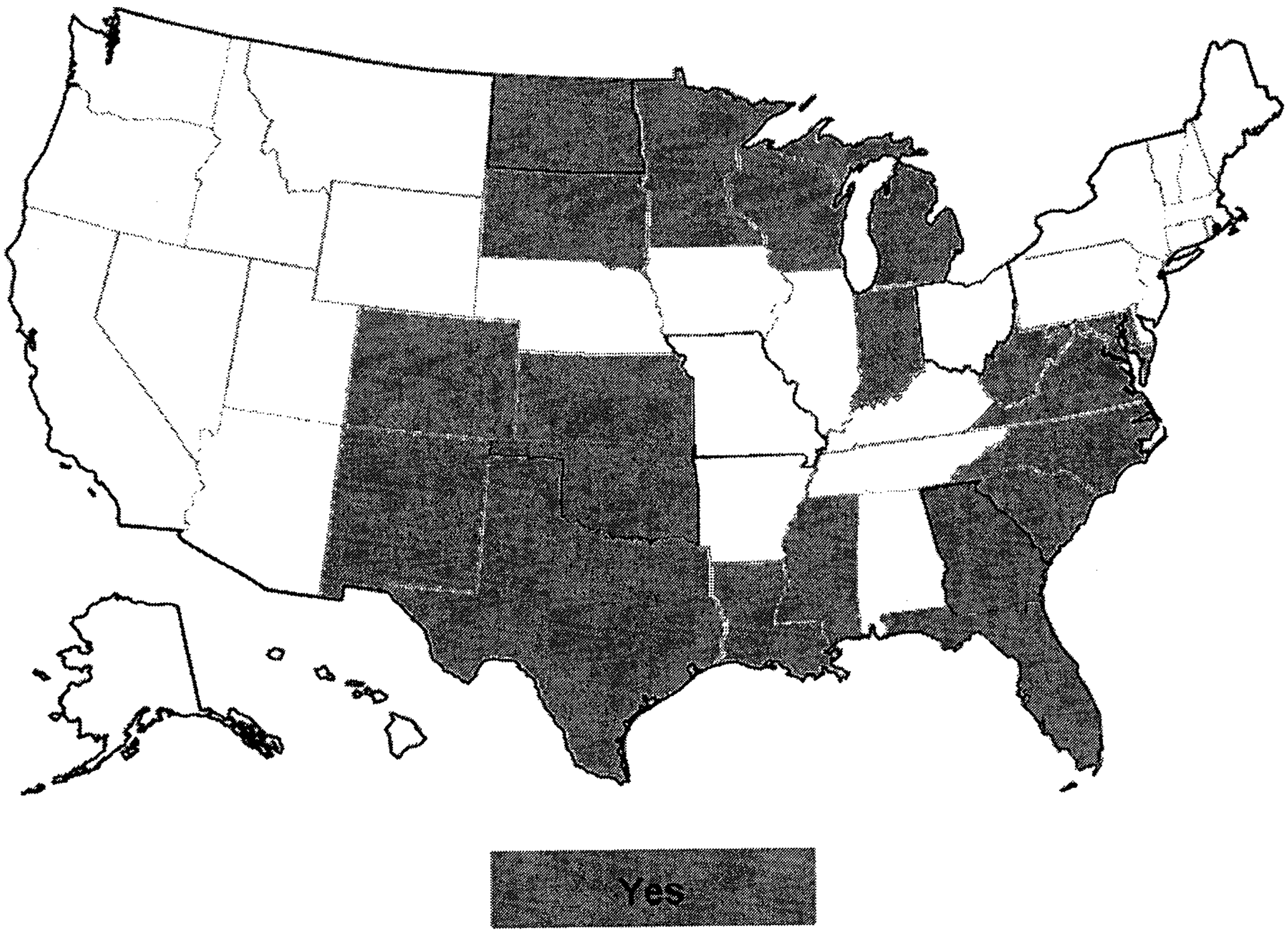
Table 2 (continued)

Jurisdiction	Company Name	Tracker Name	Eligible Investments	Case Reference
OH	Duke Energy Ohio	Infrastructure Modernization Distribution Rider	AMI	Case No 08-920-EL-SSO and 08 921-EL-AAM and 08-922-EL-UNC and 08-923-EL-ATA (December 2008)
OH	Ohio Edison	Delivery Service Improvement Rider	Distribution reliability enhancement	Case No. 08-0935-EL-SSO, 09-0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Ohio Edison	Rider AMI	Ohio Site Deployment Pilot (3 year AMI pilot)	Case No. 07-551-EL-AIR, 09-1820-EL-ATA, and 10-388-EL-SSO
OH	Ohio Edison	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No. 10-388-EL-SSO (August 2010)
OH	Ohio Power	GridSMART Rider (Phase I)	Install smart grid including AMI, Distribution Automation (DA) & Home Area Network (HAN)	Case No. 08-917-EL-SSO and 08 918-EL-SSO (March 2009)
OH	Toledo Edison	Delivery Service Improvement Rider	Distribution reliability enhancement	Case No. 08-0935-EL-SSO, 09-0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Toledo Edison	Rider AMI	Ohio Site Deployment Pilot (3 year AMI pilot)	Case No. 07-551-EL-AIR, 09-1820-EL-ATA, and 10-388-EL-SSO
OH	Toledo Edison	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No 10-388-EL-SSO (August 2010)
OH	Vectren Energy Delivery	Distribution Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No 07-1081-GA-ALT, 07-1080-GA-AIR and 08-0632-GA-AAM (January 2009)
OK	Oklahoma Gas & Electric	Smart Grid Rider	Systemwide smart grid implementation	Cause No. 201000029 (July 2010)
OK	Oklahoma Gas & Electric	System Hardening Recovery Rider	Undergrounding and other circuit hardening capex	Cause No. 20080387, Order No. 567670 (May 2009)
OK	Oklahoma Gas & Electric	OU Spirit Rider	Construction of the OU Spirit Wind Farm	Cause No 200900167, Order No 571788 (October 2009)
OR	Northwest Natural Gas	Bare steel replacement program	Replacement of bare steel	Docket No UG 177 UM 1779, Order No 07-480 (October 2007)
OR	Northwest Natural Gas	NA	Expansion of distribution system into Coos County	Docket No. UG 152, Order No. 03-236 (April 2003)
OR	Northwest Natural Gas	NA	Installation of AMI Phase II, previously subject to meter reading agreement with Portland General Electric	Docket UM 1413, Order 09-105 (March 2009)
OR	Portland General Electric	NA	Installation of AMI	Docket UE 189, Order No. 08-245 (May 2008)
PA	PPL Electric Utilities	Energy Development Rider	All interconnection equipment for renewable generation resources of 10 kW or less	Docket No. M-00031715 F0003 (August 2006); Previously R-00973954 (May 14, 1998)
PA	PPL Electric Utilities	Act 129 Compliance Rider	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket No. M-2009-2123945 (January 2010)
PA	PECO	Smart Meter Cost Recovery Rider	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket No. M-2009-2123944 (April 2010)
PA	Metropolitan Edison	Smart Meters Technologies Charge	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Electric	Smart Meters Technologies Charge	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Power	Smart Meters Technologies Charge	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket M-2009-2123950 (April 2010)
PA	Duquesne Light	Smart Meter Charge Rider	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket No. M-2009-2123948 (April 2010)
TX	AEP Texas Central	Advanced Metering System Surcharge	AMI and associated software	Docket No. 36928
TX	AEP Texas North	Advanced Metering System Surcharge	AMI and associated software	Docket No 36928
TX	Centerpoint Energy Houston Electric	Advanced Metering System Surcharge	AMI and associated software	Docket No. 35620 (August 2008)
TX	Oncor Electric Delivery	Advanced Metering System Surcharge	AMI and associated software	Docket No. 35718 (August 2008)
UT	Questar Gas	Infrastructure Rate Adjustment Tracker	Replacement of aging high-pressure feeder lines	Docket 09-057-16 (June 2010)
VA	Appalachian Power	Environmental & Reliability Cost Recovery Surcharge	Environmental & reliability related incremental costs	Docket No. PUE-2007-00069 (December 2007)
VA	Virginia Electric Power	Rider R	Costs incurred in construction of Bear Garden Generating Station and related transmission line	Case No. PUE-2009-00017 (March 2010)
VA	Virginia Electric Power	Rider S	Costs incurred in construction of Virginia City Hybrid Energy Center	Case No PUE-2007-00066 (March 2008)
VT	Central Vermont Public Service	New Initiatives Adder	Smart grid implementation including hardware, software, two-way communications systems	Dockets 7586 and 7612

Table 3: CWIP in Rate Base: Recent Retail Precedents

Jurisdiction	Company	Year Approved	Type of Project	Reference
Colorado	Public Service of Colorado	2006	Transmission, generation	Docket No. 06S-234EG
Colorado	Legislation	2007	Transmission	Senate Bill 07-100
Florida	Rulemaking	2007	Nuclear and IGCC generation	Docket 060508-EL
Florida	Florida Power & Light	2008	Nuclear generation	Docket 080650-EL
Florida	Progress Energy Florida	2008	Nuclear generation	Docket 080148-EI
Georgia	Georgia Power	2009	Nuclear generation	Docket 27800
Indiana	General Policy		Pollution Control Equipment	
Indiana	Duke Energy Indiana	2007	IGCC generation	Docket No. 43114
Kansas	Legislation	2008	Nuclear generation	Senate Bill 586
Louisiana	Rulemaking	2007	Nuclear generation	Docket R-29712
Louisiana	Cleco Power	2006	Generation	Docket U-28765
Maryland	General Policy		Environmental projects	
Michigan	Legislation	2008	Significant capital projects	House Bill 5524
Minnesota	Northern States Power- MN	2003	Pollution control	
Mississippi	Mississippi Power	2010	IGCC generation	Docket 2009-UA-14
New Mexico	Legislation	2009	All	Senate Bill 477
North Carolina	Duke Energy Carolinas	2009	Generation	Docket No. E-7, Sub 909
North Carolina	Legislation	2007	Generation	Senate Bill 3
North Dakota	Legislation	2007	Transmission, federally mandated environmental compliance projects	Senate Bill 2031 & House Bill 1221
Oklahoma	Legislation	2005	Environmental, transmission	House Bill 1910
South Carolina	South Carolina Electric & Gas	2003	Generation	Docket No 2002-223-E
South Carolina	South Carolina Electric & Gas	2009	Nuclear generation	Docket 2009-211-E
South Dakota	Legislation	2006/2007	Transmission, environmental compliance projects	
Texas	Rulemaking	2005	All Transmission within ERCOT (conditional)	Project 28884
Virginia	Legislation	2007	Reliability-related, nuclear, renewables, new generation using Virginia coal,	Senate Bill 1416
Virginia	Virginia Electric Power	2008	New generation using Virginia coal	PUE-2007-00066
West Virginia	Appalachian Power	2006	Transmission, environmental compliance, IGCC generation	Case No. 05-1278-E-PC-PW-42T
West Virginia	Monongahela Power	2007	Environmental compliance	Case No. 05-0750-E-PC
Wisconsin	Wisconsin Public Service	2000	Nuclear generation, transmission	Docket 6690-UR-112
Wisconsin	Wisconsin Public Service	2005	Generation	Docket 6690-UR-117
Wisconsin	General Policy		Diverse operations	

Figure 2: Recent Electric Precedents for CWIP in Rate Base



III. Multiyear Rate and Revenue Caps

Multiyear rate and revenue caps are performance-based ratemaking ("PBR") mechanisms that limit the true up of revenue to a utility's *own* cost for several years. The length of such plans is typically three to five years, but plans as long as ten years have been approved. Most multiyear rate plans feature an attrition relief mechanism that provides automatic rate relief for changing business conditions between rate cases. These can be designed to provide funds needed for plant additions. The rate adjustments provided by attrition relief mechanisms are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* cost growth. This can strengthen incentives to contain cost growth. Benefits of the performance improvements that are stimulated by the plan can be shared with customers.

Attrition relief mechanisms may cap the growth in allowed rates or revenue. Rate caps limit the escalation in rates (*e.g.* customer charges and cents per unit of service). They are favored where utilities are encouraged to bolster system use because rate caps strengthen incentives for sales growth and facilitate marketing flexibility. Revenue caps limit the escalation in allowed revenues (the escalation in rates then depending, additionally, on the growth in billing determinants). They are often favored in service territories with large-scale DSM programs. Revenue caps are usually combined with decoupling true ups, as discussed further below.

Multiyear rate and revenue caps commonly allow supplemental rate adjustments for changes in external business conditions that were especially difficult to anticipate at the time that the plan was fashioned. These include changes in tax rates and other government policies (*e.g.* conductor undergrounding requirements) that affect costs. Some multiyear rate and revenue caps feature earnings sharing mechanisms that automatically share earnings surpluses and/or deficits that result when the rate of return on equity ("ROE") deviates from its regulated target. Plans also sometimes feature award and/or penalty mechanisms that are linked to service quality.

Current U.S. and Canadian precedents for multiyear *rate* caps that do not involve rate freezes are indicated in Table 4 and Figure 3. Precedents for multiyear *revenue* caps are discussed in the revenue decoupling section below. Multiyear rate and revenue caps are more common for energy distributors than for vertically integrated electric utilities. This is due in part to the tendency of distribution cost to grow at a comparatively steady and predictable pace. This makes it easier to identify a fair attrition relief mechanism if accelerated programs of replacement investment aren't planned. The popularity of rate and revenue caps for power distributors also reflects the fact that they rarely experience today the combination of declining rate base and growth in average use that might permit them to operate for several years without rate escalation. Canada is moving towards multiyear rate caps for all power distributors in the two provinces that have retail competition. Rate and revenue caps are the rule rather than the exception for power distributors overseas.

Table 4: Multiyear Price Cap Precedents

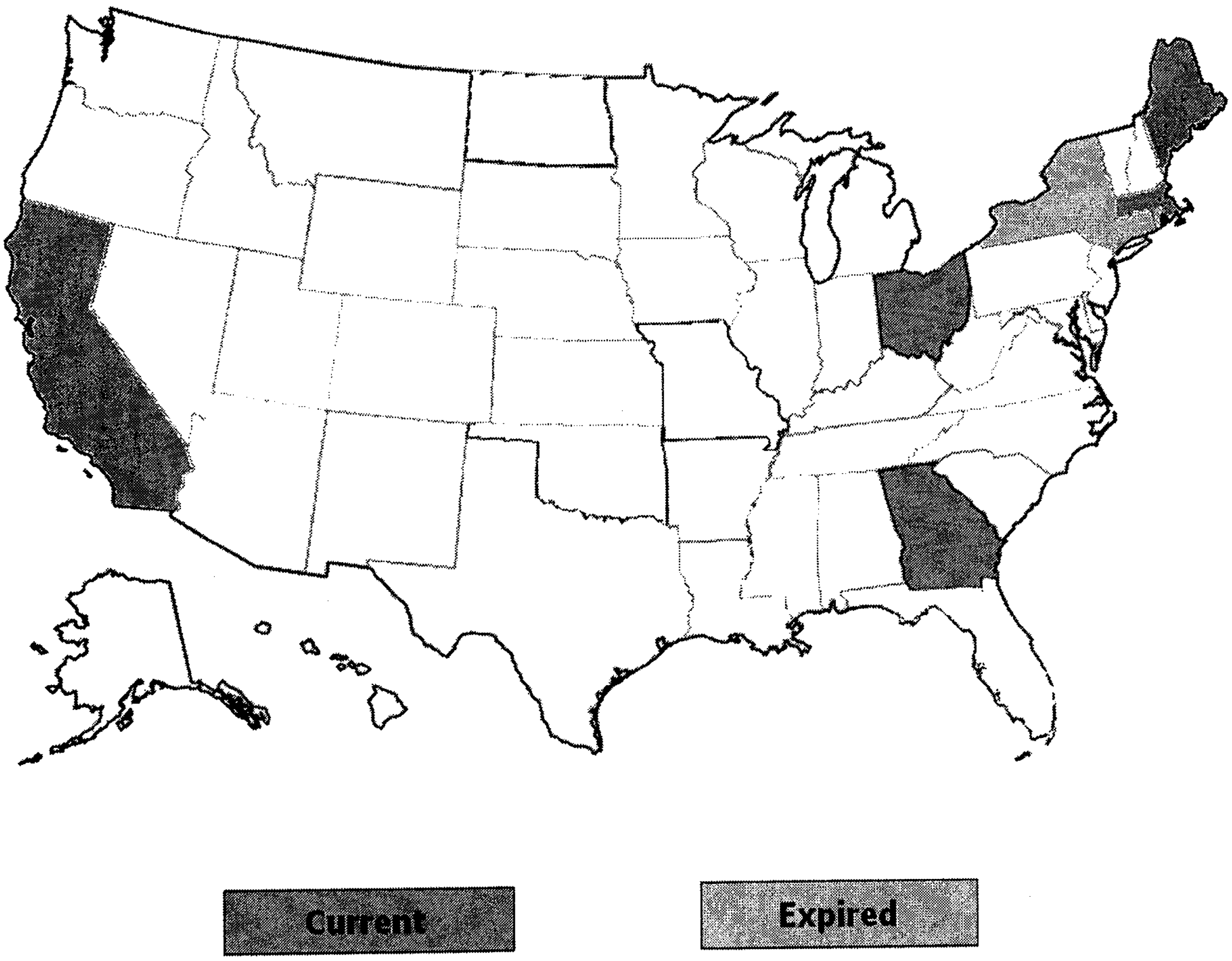
Jurisdiction	Company Name	Plan Term	Services Covered	Attrition Relief Mechanism	Case Reference
Current					
CA	PacifiCorp	2011-2013	Bundled power service	Indexing: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; major plant additions can be requested in annual filings.	Decision 10-09-010; September 2, 2010
CA	Sierra Pacific Power	2009-2011	Bundled power service	Indexing: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; major plant additions can be requested in annual filings.	Decision 09-10-041
GA	Georgia Power	2011-2014	Bundled power service	Stairstep: Rate increases permitted for DSM and the lesser of the actual plant expenditure for generating facilities or the approved capital expenditure by the Commission	Docket 31958
MA	Berkshire Gas	2002-2011	Gas distribution	No adjustment until September 2004, then Indexing: GDPPI - 1%	Docket D.T.E. 01-56
MA	Nstar	2006-2012	Power distribution	Indexing: GDPPI - X. X increases from 0.50% to 0.75% during plan.	Docket D.T.E. 05-85
ME	Bangor Gas	2000-2009, extended to 2012	Gas Distribution	Indexing: First 5 years: GDPPI Next 5 years: GDPPI-0.5%	Docket 970795 (June 26, 1998)
ME	Central Maine Power (III)	2009-2013	Power distribution	Indexing: GDPPI - 1%, separate AMI tracker	Docket 2007-215
OH	Cincinnati Gas & Electric	2009-2011	Power generation	Stairstep: Negotiated rate increases for base generation charges on January 2009 and January 2010 for all generation customers, in January 2011 rate increase only for nonresidential customers.	Case 08-920-EL-SSO
Alberta	Enmax	2007-2013	Power distribution	Index: Input Price Index -1.2%	Decision 2009-035
Ontario	All Ontario distributors	2010-2013	Power distribution	Indexing: GDP IPI for Final Domestic Demand - (0.92% to 1.32% depending on company's annual performance in benchmarking studies)	EB-2007-0673 (July 14, 2008, September 17, 2008, and January 28, 2009)
Historical					
CA	PacifiCorp	1994-1997, extended to 1999	Bundled power service	Indexing: Rates escalated by Input Price Index - X, where X=1.5% through 1997 and 1.4% through 1999, and input price index is cost-weighted index of DRI-forecasted capital, fuel, materials, and labor price indexes.	Decision 93-12-106; December 3, 1993
CA	PacifiCorp	2007-2009, extended to 2010	Bundled power service	Indexing: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; major capital additions (over $50 million) can be requested in annual filings.	Decisions 06-12-011 and 09-04-017
CA	San Diego Gas and Electric	1999-2002	Electric & Gas	Indexing: Gas & Electric separate. Attrition factor is Input Price Index - X. Input price index composed of DRI-forecasted labor, non-labor, and capital price subindexes. X factor increases during plan.	Decision 99-05-030; May 13, 1999
CA	Southern California Edison	1997-2002	Electric	Indexing: Growth in rates is CPI - X. X increases from 1.2% to 1.6% during plan	Decision 96-09-092; September 6, 1996
CT	United Illuminating	2006-2009	Power Distribution	Stairstep	Docket 05-06-04
MA	Bay State Gas	2006-2009	Gas distribution	Indexing: GDPPI - 0.51%	Docket DTE 05-27
MA	Boston Gas (I)	1997-2001	Gas distribution	Indexing: GDPPI - 0.5%	Docket D.P.U. 96-50-C (Phase I) May 16, 1997
MA	Boston Gas (II)	2004-2010	Gas distribution	Indexing: GDPPI - 0.41%	Docket DTE 03-40
MA	Blackstone Gas	November 1, 2004 - October 31, 2009	Gas distribution	Indexing	Docket D.T.E. 04-79
MA	National Grid	2000-2010	Power distribution	Rate Freeze between 2000 and 2005, Inflation: 2006-2010, inflation adjustment made based on index of regional power distribution charges.	Docket DTE 99-47 (November 29, 1999)
ME	Bangor Hydro Electric (I)	1998-2000	Power distribution	Indexing: GDPPI - 1.2%	Docket 97-116 (March 24, 1998)
ME	Central Maine Power (I)	1995-1999	Bundled power service	Indexing: 1995 GDPPI - 0.5%; for 1996 GDPPI - 1.0%, for 1997-99: (1-non-inflation driven costs)*(GDPPI-1%)	Docket 92-345 Phase II (January 10, 1995)
ME	Central Maine Power (II)	2001-2007	Power distribution	Indexing: GDPPI-X. X increases from 2% to 2.9% during plan.	Docket 99-666 (November 16, 2000)

Table 4 (continued)

Historical

Jurisdiction	Company Name	Plan Term	Services Covered	Attrition Relief Mechanism	Case Reference
NY	Brooklyn Union Gas	October 1, 1991 - September 30, 1994	Gas distribution	Stairstep: Rate year 1 increase in rates of $35.7 million. Increases for rate years 2 and 3 to be based upon a forecast that parties agree to.	Case 90-G-0981, Opinion 91-21, October 9, 1991
NY	Brooklyn Union Gas	October 1, 1994 - September 30, 1997	Gas distribution	Stairstep: No rate increase in year 1. Rates for years 2 and 3 based on a formula and limited to the rate of inflation	Case 93-G-0941, Opinion 94-22, October 18, 1994
NY	Central Hudson Gas & Electric	July 1, 2006 - June 30, 2009	Electric & Gas	Stairstep: Electric rate increases of $41.5, $6.4, and $5.5 million for rate years 1, 2, and 3 respectively. Gas rate increases of $8.003 million for rate year 1, $6.057 million for rate year 2, and no gas rate increase for rate year 3 approved.	Case 05-E-0934 & Case 05-G-0935; July 24, 2006
NY	Consolidated Edison	October 1, 1994 - September 30, 1997	Gas Distribution	Hybrid: Rate year 1 increase of $7,735,000. Rate years 2 and 3 projected rate increases are $20.4 million and $21.7 million, subject to a cap defined as the lesser of the latest GDP deflator forecast + 1% + incentives or 4.8%. Any expenses unrecovered due to cap deferred for later recovery.	Case 93-G-0996, Opinion 94-21, October 12, 1994
NY	Consolidated Edison	April 1, 2005 - March 31, 2008	Power distribution	Stairstep	Case 04-E-0572, March 24, 2005
NY	Long Island Lighting Company	December 1, 1993- November 30, 1996	Gas distribution	Stairstep: Revenue increases of $25.6 million in rate year 1, $23 million in rate year 2, and $20 million in rate year 3	Case 93-G-0002, Opinion 93-23, December 23, 1993
NY	New York State Electric & Gas	December 1, 1993 - August 31, 1995	Gas	Stairstep: Gas revenues increase by $7.6 million in rate year 1, $7 million in rate year 2, and $7.2 million in rate year 3.	Case 92-G-1086, Opinion 93-22, November 9, 1993
NY	New York State Electric & Gas	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	Electric	Stairstep: Rate increases of $45.1 million, $45.3 million, and $45.5 million approved for rate years 1, 2, and 3, respectively.	Case 94-M-0349, Opinion 95-27, September 27, 1995
NY	Niagara Mohawk	July 1, 1990 - December 31, 1992	Gas	Stairstep: Revenue increases of $27.2 million, $0, and $5.5 million for Rate Years 1, 2, and 3, respectively.	Case 29327, Opinion 89-37, June 28, 1991
NY	Orange & Rockland Utilities	November 1, 2003- October 31, 2006	Gas	Stairstep: First year rate increase of $9.25 million, Second rate year increase of $7.375 million, Third year rate increase of $5.00 million; rate increases for second and third rate year can be supplemented by a total of $1.9 million for verified system safety and reliability improvements incurred during the first and second rate years	Case 02-G-1553, October 23, 2003
NY	Orange & Rockland Utilities	November 1, 2006 - October 31, 2009	Gas	Stairstep: First year rate increase of $6.5 million, Second rate year increase of $6.5 million, Third year rate increase of $1.8 million	Case 05-G-1494, October 20, 2006
NY	Rochester Gas & Electric	July 1, 1993 - June 30, 1996	Gas	Stairstep: Rate increases of $2.6 million, $4.4 million, and $4.3 million, respectively for rate years 1, 2, and 3.	Case 92-G-0741, Opinion No. 93-19; August 24, 1993
OH	Columbus Southern Power, Ohio Power	2006-2008	Power Generation	Stairstep: 3% rate increase per year for Columbus Southern, 7% rate increase per year for Ohio Power	Case No. 04-169-EL-UNC (January 2005)
RI	Blackstone Valley Electric, Montaup Electric	1997-1998	Power Distribution	Indexing: CPI	Docket 2514
RI	Narragansett Electric	1997-1998	Power Distribution	Indexing: CPI	House Bill 8124, Substitute B3
Alberta	Northwestern Utilities	1999-2002	Bundled power service	Stairstep: fixed price increases of 0.5% (1999), 1% (2000, 2001), 2% (2002)	Decision U98060 (March 31, 1998)
Alberta	EPCOR	2002-2005, Terminated 12/31/2003	Power distribution	Indexing: Rate Increase of 85% of Input Price Index; Input Price Index constructed of 48% CPI, 52% 5-year rolling average Industrial Product Price Index	Distribution Tariff Bylaw 12367 (August 18, 2000)
Ontario	All Ontario distributors	2000-2003	Power distribution	Indexing: Input Price Index -1.5%	RP-1999-0034
Ontario	All Ontario Distributors	2006-2009	Power Distribution	Indexing: GDP IPI for final domestic demand - 1%	EB-2006-0089 (December 20, 2006)
Ontario	Union Gas	2001-2003	Gas distribution	Indexing: GDP IPI -2.5%	RP-1999-0017 (July 21, 2001)

Figure 3: Recent Electric Rate Cap Precedents by State



IV. Revenue Decoupling

The term revenue decoupling refers to a group of regulatory provisions designed to facilitate recovery of allowed base rate (fixed cost) revenue and so weaken the link between a utility's revenue and the volume of its services. This reduces the utility's disincentive to promote energy efficiency and can alleviate the financial stress caused by stagnant or declining average use. Energy efficiency programs can yield substantial cost savings for customers. Three approaches to decoupling are well established: decoupling true up plans, lost revenue adjustment mechanisms ("LRAMs"), and fixed variable pricing.

A. Decoupling True Up Plans

Decoupling true up plans are designed to help a utility's actual revenue track the revenue allowed by regulators. Most decoupling true up plans have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism ("RAM"). A typical RDM tracks variances between actual and allowed revenue and makes periodic true ups. Utilities are compensated for any net decline in average use and denied the benefit from any net growth in average use.

True ups may be made annually or more frequently. More frequent adjustments cause actual and allowed revenue to match up better in a given year so that rates fluctuate less from year to year. The size of the true up that is allowed in a given year is sometimes capped. A "soft" cap permits utilities to defer for later recovery any account balances that cannot be recovered immediately.

RDMs vary in the scope of utility services to which they apply. Quite commonly, only revenues from residential and smaller business customers are decoupled. These customers account for an especially high share of the base rate revenue of energy distributors and are usually the primary targets of DSM programs. RDMs also vary in terms of the service classes for which revenues are pooled for true up purposes. In some plans, all service classes are placed in the same "basket". In others, multiple baskets are created to insulate customers of services in each basket from trends in the demands for services in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between *weather normalized* revenue and allowed revenue. An RDM that instead accounts for *all* sources of demand variance is called a "full" decoupling mechanism.

The RAM component of a decoupling true up plan is an attrition relief mechanism that escalates allowed revenue between rate cases. Some RAMs are "broad-based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures and thereby make it possible to reduce rate case frequency. A broad-based RAM provides the basis for a multiyear revenue cap. When RAMs are not broad-based, utilities usually retain the right to file rate cases during the decoupling plan and frequently do file.

Several approaches to RAM design have been established. These approaches include stairsteps, indexing, hybrids, and revenue per customer freezes. Stairsteps provide predetermined increases in allowed revenue which often reflect forecasts of cost growth. Indexing escalates allowed revenue for inflation and frequently also for customer growth. In North America, hybrid RAMs typically involve indexes for O&M expenses and stairsteps for capital costs. Revenue per customer freezes escalate the revenue requirement only for customer growth. All but the last of these approaches is broad-based and provides the basis for a multiyear revenue cap.

States that have tried gas and electric decoupling true up plans are indicated on the maps in Figures 4a and 4b, respectively. Decoupling true up plan precedents in the United States, Australia, and Canada are detailed in Table 5. It can be seen that there are more plans for gas utilities than for electric utilities. This reflects the more pervasive character of the declining average use problem facing gas distributors. However, decoupling true up plans have become common for electric utilities that experience some decline in average use due to large DSM programs. Note also that most RAMs for electric utilities are broad-based, whereas most RAMs for gas utilities are revenue per customer freezes. Gas distributors are presumably more willing to settle for an undercompensatory RAM in return for relief from declining average use.

B. Lost Revenue Adjustment Mechanisms

An LRAM explicitly compensates a utility for base rate revenues that are estimated to be lost due to its DSM programs. Compensation for lost margins is usually effected through a rate rider. Estimates of energy (and sometimes also peak load) savings are needed for LRAM calculations. The utility remains at risk for fluctuations in volumes and peak load due to weather, local economic activity, power market prices, and other volatile demand drivers.

Compensation is not confined to *declines* in average use, as it is under decoupling true up plans. This is desirable because a DSM program that causes billing determinants to grow more slowly than cost increases the need for frequent rate cases even if average use does not decline. Overearning is still unlikely under typical operating conditions.

Precedents for LRAMs are detailed in Table 6 and Figure 5. It can be seen that LRAMs are less widely used than decoupling true up plans today. However, they have experienced a rebound recently due to their use in Duke Energy's "Save a Watt" approach to DSM regulation ongoing in several states.

Figure 4a: Electric Decoupling True Up Plans by State

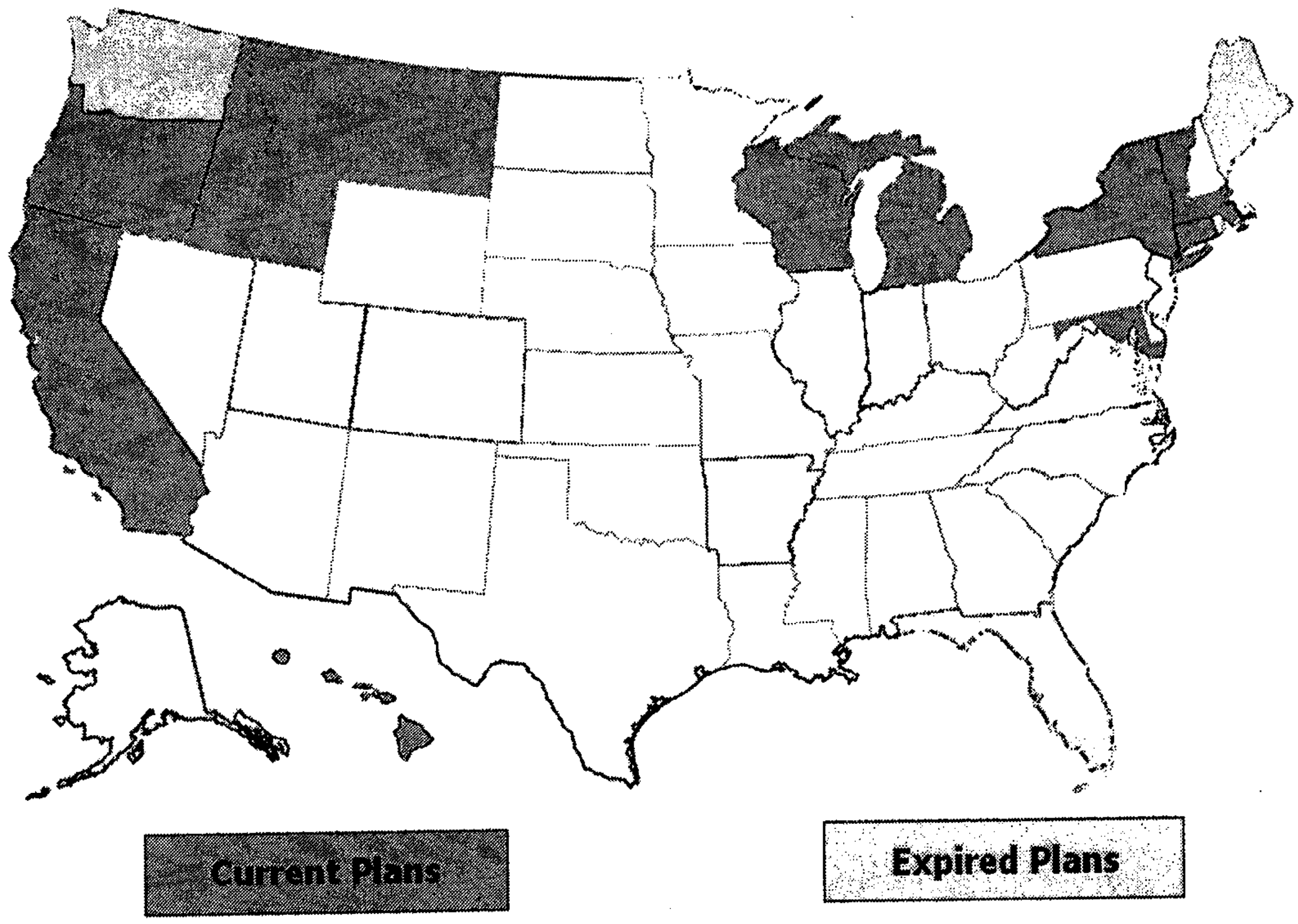


Figure 4b: Gas Decoupling True Up Plans by State

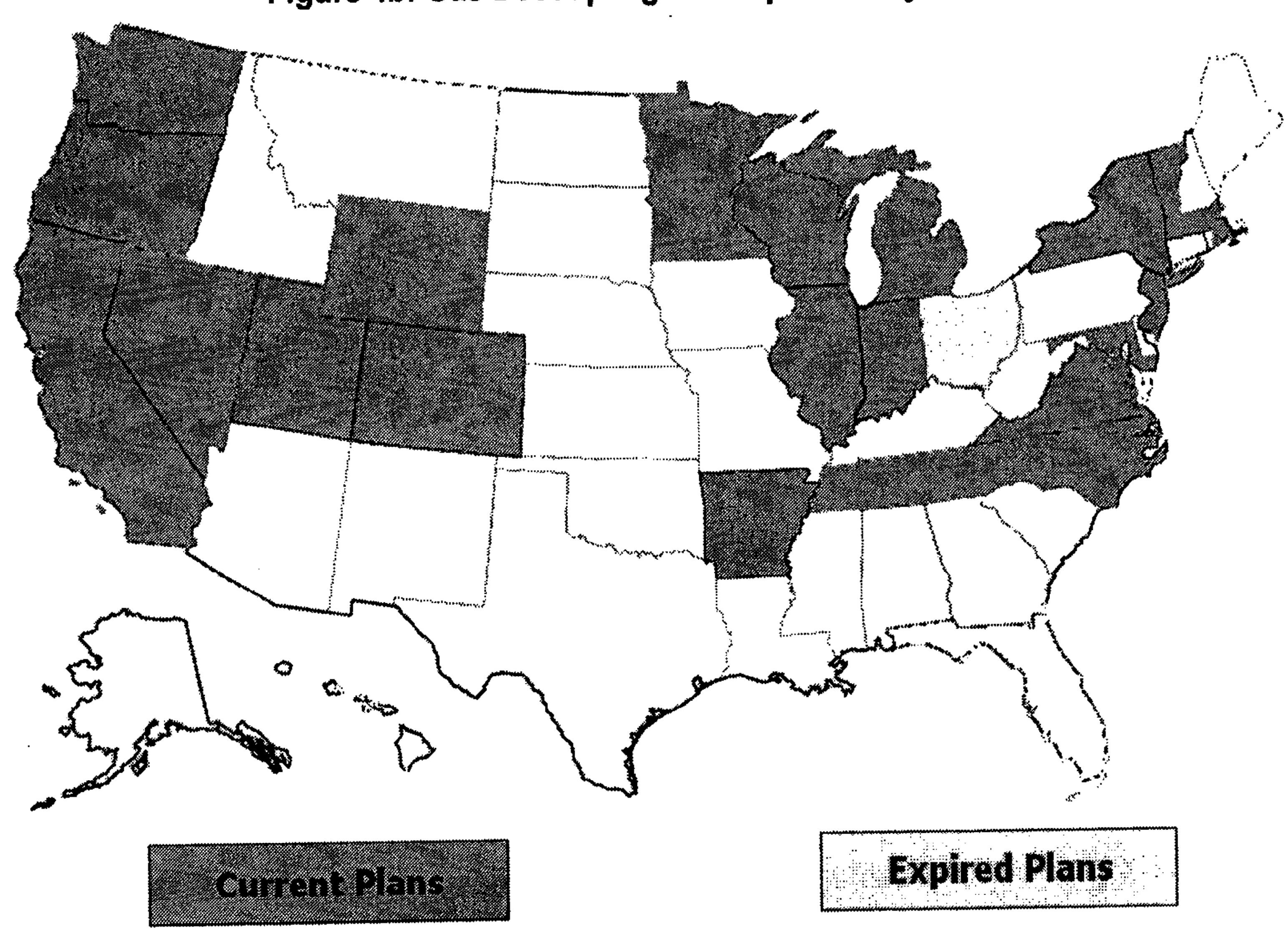


Table 5: Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
			Current		
Canada					
BC	Terasen Gas	Gas	2010-2011	Hybrid	Order G-141-09
BC	Pacific Northern Gas	Gas	2003-open	RPC Freeze	N/A
ON	Enbridge Gas Distribution	Gas	2008-2012	Inflation Indexing	Docket EB-2007-0615
ON	Union Gas	Gas	2008-2012	Inflation Indexing	Docket EB-2007-0606
QU	Gaz Metro	Gas	2007-2012	Inflation Indexing	R-3599-2006
United States					
AR	CenterPoint Energy	Gas	2008-2010	RPC Freeze	Docket 06-161-U
AR	Arkansas Oklahoma Gas	Gas	2007-2011	RPC Freeze	Docket 07-026-U
AR	Arkansas Western	Gas	2007-2010	RPC Freeze	Docket 06-124-U
CA	Southwest Gas	Gas	2009-2013	Stairstep	Decision 08-11-048
CA	Southern California Edison	Electric	2009-2011	Stairstep	Decision 09-03-025
CA	Southern California Gas	Gas	2008-2011	Stairstep	Decision 08-07-046
CA	San Diego Gas & Electric	Electric & Gas	2008-2011	Stairstep	Decision 08-07-046
CO	Public Service Company of Colorado	Gas	2008-2011	RPC Freeze	Decision C07-0568
CT	United Illuminating	Electric	2009-2010	Stairstep	Docket No. 08-07-04
DC	Potomac Electric Power	Electric	2010-open	RPC Freeze	Order 15556
HI	Hawaiian Electric Company	Bundled Power	2010-2011	Hybrid	Docket No. 2008-0274
HI	Hawaiian Electric Light Company	Bundled Power	2010-2011	Hybrid	Docket No. 2008-0274
HI	Maui Electric Company	Bundled Power	2010-2011	Hybrid	Docket No. 2008-0274
ID	Idaho Power	Electric	2010-2012	RPC Freeze	Case No. IPC-E-09-28
IL	North Shore Gas	Gas	2008-2012	RPC Freeze	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-2012	RPC Freeze	Case 07-0242
IN	Vectren Energy	Gas	2007-open	RPC Freeze	Cause No. 43046
IN	Vectren Southern Indiana	Gas	2007-open	RPC Freeze	Cause No. 43046
IN	Citizens Gas	Gas	2007-2011	RPC Freeze	Cause No. 42767
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MA	Massachusetts Electric	Electric	2010-open	No RAM	DPU 09-39
MA	Bay State Gas	Gas	2009-open	No RAM	DPU 09-30
MA	Boston-Essex Gas	Gas	2010-open	No RAM	DPU 10-55
MA	Colonial Gas	Gas	2010-open	No RAM	DPU 10-55
MD	Baltimore Gas & Electric	Electric	2008-open	RPC Freeze	Letter Orders ML 108069, 108061
MD	Delmarva Power & Light	Electric	2007-open	RPC Freeze	Order No. 81518
MD	Potomac Electric Power	Electric	2007-open	RPC Freeze	Order No. 81517
MD	Chesapeake Utilities	Gas	2006-open	RPC Freeze	Order No. 81054
MD	Washington Gas Light	Gas	2005-open	RPC Freeze	Order No. 80130
MD	Baltimore Gas & Electric	Gas	1998-open	RPC Freeze	Case No. 8780
MI	Detroit Edison	Electric	2010-2011	RPC Freeze	Case No. U-15768
MI	Michigan Consolidated Gas	Gas	2010-2011	RPC Freeze	Case No. U-15985
MI	Consumers Energy	Gas	2010-2011	RPC Freeze	Case No. U-15986
MI	Consumers Energy	Electric	2009-2011	RPC Freeze	Case No. U-15645
MI	Michigan Gas Utilities	Gas	2010-2011	RPC Freeze	Case No. U-15990
MI	Upper Peninsula Power	Electric	2010-2011	RPC Freeze	Case No. U-15988
MN	CenterPoint Energy	Gas	2010-2013	RPC Freeze	GR-08-1075
MT	Northwestern Energy	Electric	2011-2015	RPC Freeze	Docket No. 2009.9.129
NC	Public Service Co of NC	Gas	2008-open	RPC Freeze	Docket No. G-5, Sub 495
NC	Piedmont Natural Gas	Gas	2008-open	RPC Freeze	Docket No. G-9, Sub 550
NJ	New Jersey Gas Natural	Gas	2010-2013	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2010-2013	RPC Freeze	Docket GR05121019
NV	Southwest Gas	Gas	2009-open	RPC Freeze	D-09-04003
NY	Niagara Mohawk	Electric	2011-open	No RAM	Case 10-E-0050
NY	New York State Electric & Gas	Electric & Gas	2010-2013	Stairstep	Case 09-E-0715
NY	Rochester Gas & Electric	Electric & Gas	2010-2013	Stairstep	Case 09-E-0717

Table 5 (continued)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
NY	Consolidated Edison	Gas	2010-2013	Stairstep	Case 09-G-0795
NY	Consolidated Edison	Electric	2010-2013	Stairstep	Case 09-E-0428
NY	Central Hudson G&E	Electric & Gas	2010-2013	Stairstep	Case 09-E-0588
NY	Orange & Rockland Utilities	Gas	2009-2012	Stairstep	Case 08-G-1398
NY	Niagara Mohawk	Gas	2009-open	RPC Freeze	Case 08-G-0609
NY	Orange & Rockland Utilities	Electric	2008-2011	Stairstep	Case 07-E-0949
NY	National Fuel Gas	Gas	2008-open	RPC Freeze	Case 07-G-0141
OR	Northwest Natural Gas	Gas	2009-2012	RPC Freeze	Order No. 07-426
OR	Portland General Electric	Electric	2011-2013	RPC Freeze	Order No. 10-478
OR	Cascade Natural Gas	Gas	2006-2010	RPC Freeze	Order No. 06-191
TN	Chattanooga Gas	Gas	2010-2013	RPC Freeze	Docket 09-0183
UT	Questar Gas	Gas	2010-open	RPC Freeze	Docket No. 09-057-16
VA	Washington Gas Light	Gas	2010-2013	RPC Freeze	Case No. PUE-2009-00064
VA	Columbia Gas of Virginia	Gas	2010-2012	RPC Freeze	Case No. PUE-2009-00051
VA	Virginia Natural Gas	Gas	2009-2012	RPC Freeze	Case No. PUE-2008-00060
VT	Green Mountain Power	Electric	2010-2013	Inflation Indexing	Docket No. 7585
VT	Central Vermont Public Service	Electric	2009-2011	Inflation Indexing	Docket No. 7336
VT	Vermont Gas Systems	Gas	2007-2011	Hybrid	Docket No. 7109
WA	Avista	Gas	2009-open	RPC Freeze	Docket UG-060518
WA	Cascade Natural Gas	Gas	2005-2010	RPC Freeze	Docket UG-060256
WI	Wisconsin Public Service	Electric & Gas	2009-2012	RPC Freeze	D-6690-UR-119
WY	Questar Gas	Gas	2009-2012	RPC Freeze	Docket 30010-94-GR-08
WY	SourceGas Distribution	Gas	2011-open	RPC Freeze	Docket 30022-148-GR-10
Australia					
Federal	ElectraNet	Power Transmission	2008-2012	Hybrid	Final Decision (11 April 2008)
Federal	Powerlink	Power Transmission	2007-2011	Hybrid	Final Decision (14 June 2007)

Historical

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Canada					
BC	Terasen Gas	Gas	2008-2009	Hybrid	Order G-33-07
BC	Terasen Gas	Gas	2004-2007	Hybrid	Order G-51-03
BC	BC Gas	Gas	2000-2001	Hybrid	Order G-48-00
BC	BC Gas	Gas	1998-2000	Hybrid	Order G-85-97
BC	BC Gas	Gas	1996-1997	Hybrid	N/A
BC	BC Gas	Gas	1994-1995	Hybrid	Order G-59-94
United States					
CA	Pacific Gas & Electric	Electric & Gas	2007-2010	Stairstep	Decision 07-03-044
CA	Southern California Edison	Electric	2006-2008	Hybrid	Decision 06-05-016
CA	San Diego Gas & Electric	Electric & Gas	2005-2007	Inflation Indexing	Decision 05-03-025
CA	Southern California Gas	Gas	2005-2007	Inflation Indexing	Decision 05-03-025
CA	Southern California Edison	Electric	2004-2006	Hybrid	Decision 04-07-022
CA	Pacific Gas & Electric	Gas & Elec Dx/Gen	2004-2006	Inflation Indexing	Decision 04-05-055
CA	Southern California Edison	Electric	2002-2003	Inflation Indexing	Decision 02-04-055
CA	Southern California Gas	Gas	1998-2002	Inflation Indexing	Decision 97-07-054
CA	San Diego Gas & Electric	Electric & Gas	1994-1999	Hybrid	Decision 94-08-023
CA	Pacific Gas & Electric	Electric	1993-1995	Hybrid	Decision 92-12-057
CA	Southern California Gas	Gas	1990-1993	Hybrid	Decision 90-01-016
CA	Pacific Gas & Electric	Electric	1990-1992	Hybrid	Decision 89-12-057
CA	San Diego Gas & Electric	Electric	1989-1993	Hybrid	Decision 89-11-068
CA	Southern California Edison	Electric	1986-1991	Hybrid	Decision 85-12-076
CA	Southern California Gas	Gas	1986-1989	Hybrid	Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1986-1989	Hybrid	Decision 85-12-076
CA	San Diego Gas & Electric	Electric & Gas	1986-1988	Hybrid	Decision 85-12-108
CA	Pacific Gas & Electric	Electric	1984-1985	Hybrid	Decision 83-12-068
CA	PacifiCorp	Electric	1984-1985	Stairstep	Decision 89-09-034
CA	Southern California Edison	Electric	1983-1984	Hybrid	Decision 82-12-055
CA	San Diego Gas & Electric	Electric & Gas	1982-1983	Hybrid	Decision 93892
CA	Pacific Gas & Electric	Electric & Gas	1982-1983	Hybrid	Decision 93887
CA	Southern California Gas	Gas	1981-1982	Stairstep	Decision 92497
CA	Southern California Gas	Gas	1979-1980	Stairstep	Decision 89710
CA	Pacific Gas & Electric	Gas	1978-1981	No RAM	Decisions 89316,91107

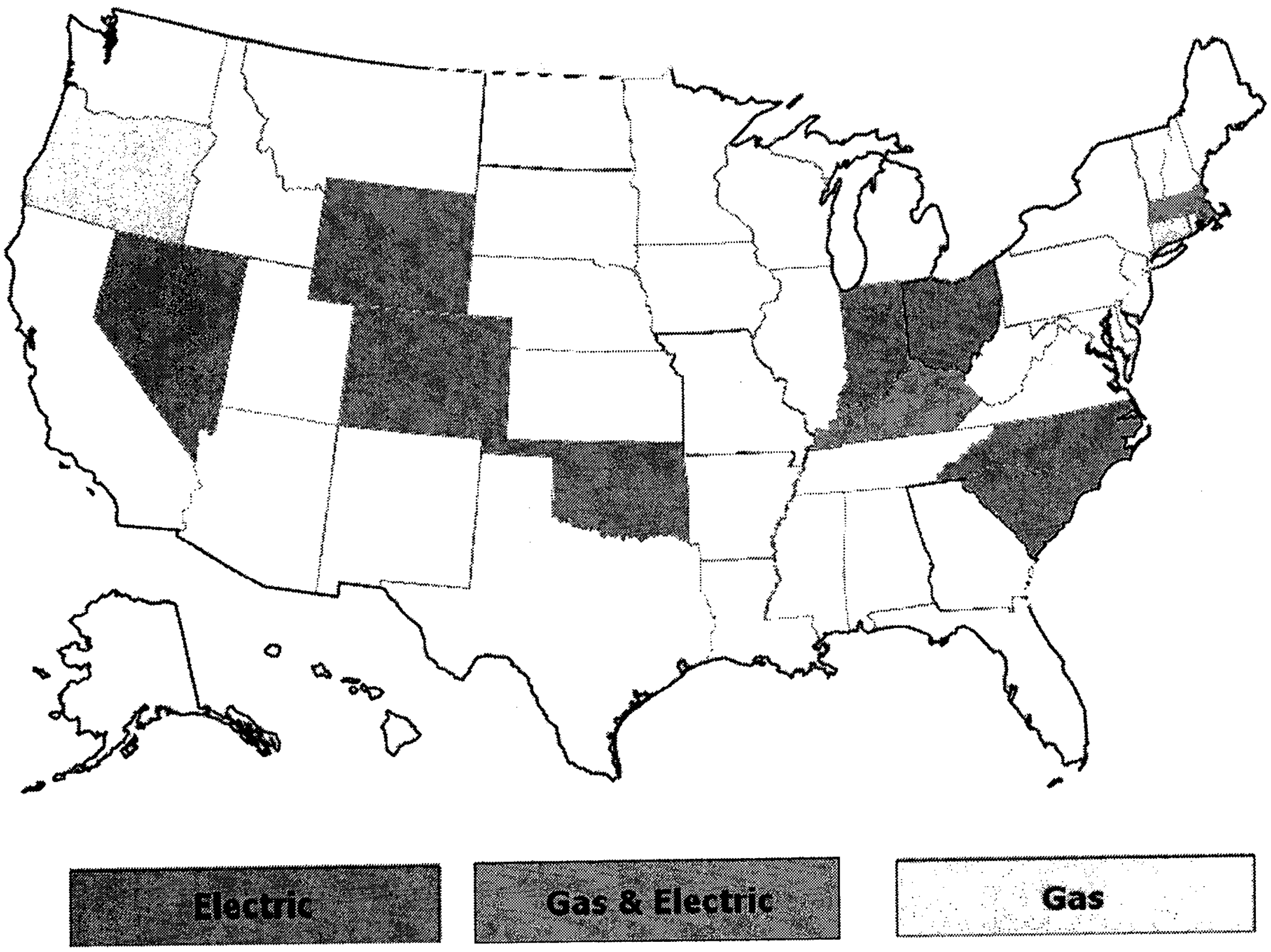
Table 5 (continued)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
FL	Florida Power Corporation	Electric	1995-1997	RPC Freeze	Docket 930444
ID	Idaho Power	Electric	2007-2009	RPC Freeze	Case No. IPC-E-04-15
ME	Central Maine Power	Electric	1991-1993	RPC Freeze	Docket No. 90-085
MT	Montana Power Company	Electric	1994-1998	RPC Freeze	Docket No. 93.6.24
NC	Piedmont Natural Gas	Gas	2005-2008	RPC Freeze	Docket G-44 Sub 15
NJ	New Jersey Gas Natural	Gas	2007-2010	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	RPC Freeze	Docket GR05121019
NY	Central Hudson G&E	Gas	2009-open	RPC Freeze	Case 08-E-0888
NY	Central Hudson G&E	Electric	2009-open	No RAM	Case 08-E-0887
NY	Consolidated Edison	Electric	2008-open	No RAM	Case 07-E-0523
NY	Consolidated Edison	Gas	2007-2010	Stairstep	Case 06-G-1332
NY	Rochester Gas & Electric	Electric	1993-1996	Stairstep	Opinion No. 93-19
NY	New York State Electric & Gas	Electric	1993-1995	Stairstep	Opinion No. 93-22
NY	Consolidated Edison	Electric	1992-1995	Stairstep	Opinion No. 92-8
NY	Long Island Lighting Company	Electric	1992-1994	Stairstep	Opinion No. 92-8
NY	Orange & Rockland Utilities	Electric	1991-1993	Stairstep	Case 89-E-175
NY	Niagara Mohawk	Electric	1990-1992	Stairstep	Case 94-E-0098
OH	Vectren Energy	Gas	2007-2009	RPC Freeze	Case 05-1444-GA-UNC
OR	Portland General Electric	Electric	2009-2010	RPC Freeze	Order No. 09-020
OR	Northwest Natural Gas	Gas	2005-2009	RPC Freeze	Order No. 05-934
OR	Northwest Natural Gas	Gas	2002-2005	RPC Freeze	Order No. 02-634
OR	PacifiCorp	Electric	1998-2001	Inflation Indexing	Order No. 98-191
OR	Portland General Electric	Electric	1995-1996	Stairstep	Order No. 95-0322
UT	Questar Gas	Gas	2006-2010	RPC Freeze	Docket No. 05-057-T01
VT	Green Mountain Power	Electric	2007-2010	Stairstep	Docket No. 7176
WA	Avista	Gas	2007-2009	RPC Freeze	Docket UG-060518
WA	Puget Sound & Power	Electric	1991-1995	RPC Freeze	Docket UE-901184-P
Australia					
Federal	EnergyAustralia	Power Transmission	2004-2009	Hybrid	File No: S2004/138
Federal	TransGrid	Power Transmission	2004-2009	Hybrid	File No: M2003/287
Federal	ElectraNet	Power Transmission	2003-2007	Hybrid	File No: C2001/1094
Federal	Powerlink	Power Transmission	2002-2006	Hybrid	File No: 2000/659
Federal	EnergyAustralia	Power Transmission	1999-2004	Hybrid	File No: CG98/118
Federal	TransGrid	Power Transmission	1999-2004	Hybrid	File No: CG98/118
Federal	Snowy Mountains	Power Transmission	1999-2004	Hybrid	File No: C1999/62
New South Wales	Energy Australia	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Integral Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Advance Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Great Southern Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Northern Electric	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Australian Inland Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
Tasmania	Transcend Networks	Power Transmission	2004-2008	Hybrid	File No: C2001/1100
Victoria	SPI PowerNet	Power Transmission	2003-2008	Hybrid	File No: C2001/1093
Victoria	VENCorp	Power Transmission	2003-2007	Hybrid	File No: C2001/1093

Table 6: Recent LRAM Precedents

State	Company	Services	Currently Effective	Case Reference	Name of Mechanism
CO	Public Service of Colorado	Electric	Yes	Docket 07A-420 E. Decision C08-560	
CT	Connecticut Natural Gas	Gas	Yes	Docket No. 93-02-04	Conservation Adjustment Mechanism (CAM)
CT	Southern Connecticut Gas	Gas	Yes	Docket No. 93-03-09	Conservation Adjustment Mechanism (CAM)
IN	Duke Energy Indiana (PSI)	Electric	Yes	Cause No 43374	
IN	Indiana-Michigan Power	Electric	Yes	Cause 43827	
KY	Delta Natural Gas	Gas	Yes	Docket No. 2008-00062	Conservation/Efficiency Program Cost Recovery
KY	Louisville Gas & Electric	Electric & Gas	Yes	Order No. 199300150-05101993	Demand-Side Management Cost Recovery Mechanism
KY	Kentucky Utilities	Electric	Yes	Order No. 200000459-051101	
KY	Duke Energy Kentucky	Electric	Yes	Docket No 95-321	
MA	Berkshire Gas/Energy East	Gas	Yes	D.P.U 91-154	Local Distribution Adjustment Clause (LDAC)
MA	Fitchburg Gas and Electric Light/Uniti	Gas	Yes	D.P.U. 98-51	
MA	NSTAR Electric	Electric	Yes	D.P.U. 10-06	Energy Efficiency Charge
MA	NSTAR Gas	Gas	Yes	D.P.U 91-93 D.P.U. 92-116	
MA	New England Gas Company	Gas	Yes	D.P.U 02-36	Local Distribution Adjustment Clause (LDAC
MT	Northwestern Energy	Electric	No	Docket No. D2004.6.90, Interim Order No 6574	
NC	Duke Energy Carolinas	Electric	Yes	Docket No. E-7, Sub 831	
NC	Progress Energy Carolinas (Carolina Power & Light)	Electric	Yes	Docket No E-2, Sub 931	
NV	Nevada Energy	Electric	Yes	Docket 09-07016	
OH	Duke Energy Ohio (Cincinnati Gas & Electric)	Electric	Yes	Docket No. 06-0091-EL-UNC	Called Energy Efficiency Cost Recovery Rider
OK	Empire District Electric	Electric	Yes	Cause No 200900146 Order 571326	Demand-Side Management Cost Recovery Mechanism
OK	Oklahoma Gas & Electric	Electric	Yes	Cause No. 200800059 Order 556179	Class Lost Revenue Factor included in the Demand Program Rider
OK	Public Service of Oklahoma	Electric	Yes	Cause No 200800144 Order 564437	Demand-Side Management Cost Recovery Mechanism
ON	Union Gas	Gas	Yes	EB-2007-0606	Lost Revenue Adjustment Mechanism
ON	Enbridge Gas Distribution	Gas	Yes	EB-2007-0615	Lost Revenue Adjustment Mechanism
ON	Toronto Hydro-Electric	Electric	Yes	EB-2007-0096	Lost Revenue Adjustment Mechanism
OR	Avista Utilities	Gas	Yes	Order 93-1881	
SC	Progress Energy Carolinas	Electric	Yes	Docket No. 2008-251-E Order 2009-373	Demand-Side Management Cost Recovery Mechanism
SC	Duke Energy Carolinas	Electric	Yes	Docket No. 2009-226-E Order No. 2010-79	
WY	Montana-Dakota Utilities	Electric	Yes	Docket No 20004-65-ET-06	

Figure 5: Current LRAMs by State



C. Fixed Variable Pricing

Fixed variable pricing is an approach to the design of base rates that increases the proportion of fixed costs (costs that do not vary in the short run with system use) which is recovered through fixed charges (charges that do not vary with the sales volume or peak demand). A *straight* fixed variable ("SFV") rate design recovers *all* fixed costs through fixed charges. A rate design that recovers a substantial but more limited share of fixed costs through fixed charges is sometimes called *modified* fixed variable ("MFV") pricing. Most approved fixed variable rate designs implemented to date have involved the same fixed charge for all customers in a service class. However, "sliding scale" rate designs have been developed which assign lower fixed charges to customers who have historically had low volumes.

SFV pricing has been used on a large scale by the Federal Energy Regulatory Commission ("FERC") since the early 1990s to regulate natural gas pipelines. Precedents for fixed variable pricing in retail ratemaking are shown in Figure 6 and Table 7. It can be seen that fixed variable retail pricing has to date been more common for gas utilities than for electric utilities. Ohio is noteworthy for having recently switched from the true up approach to decoupling to fixed variable pricing. In addition to the precedents listed here, several states have in recent years made sizable steps in the direction of fixed variable pricing by redesigning rates for small volume customers to raise customer charges and lower volumetric charges substantially. Fixed charges are generally much higher for investor-owned utilities in Canada than in the United States.

Most fixed variable rate designs feature uniform fixed charges within service classes, but utilities in at least three states (Florida, Georgia, and Oklahoma) have fixed charges that vary in some rough fashion with delivery volumes.

Figure 6: Fixed Variable Pricing Precedents by State

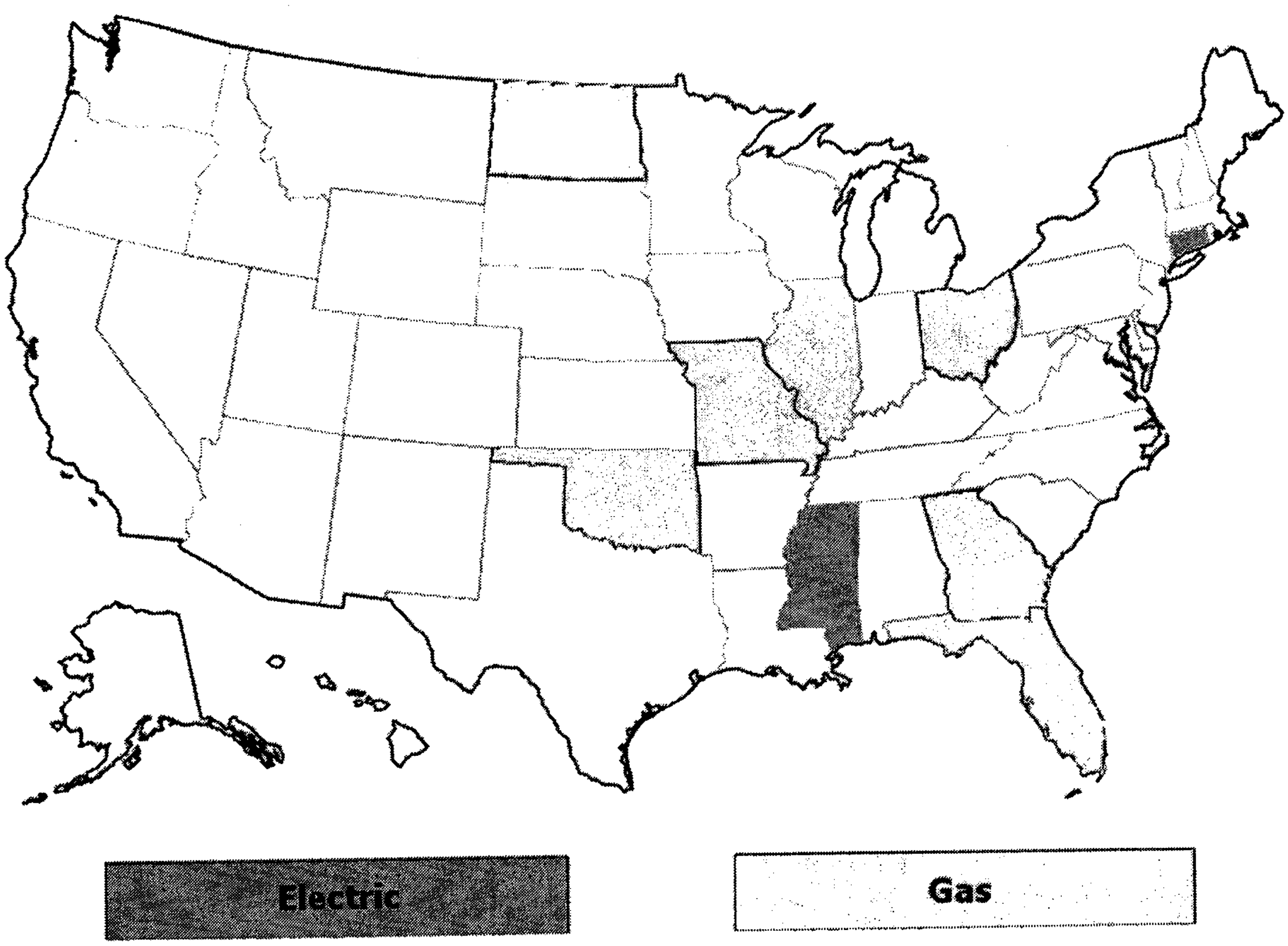


Table 7: Fixed Variable Retail Pricing Precedents

Jurisdiction	Company Name	Services	Years in Place	Case Reference
CT	Connecticut Light & Power	Electric	2007-open	Docket 07-07-01
FL	Peoples Gas	Gas	2009-open	Docket 080318-GU
GA	Altanta Gas Light	Gas	1998-open	Docket No. 8390-U
IL	Ameren CILCO	Gas	2008-2012	Case 07-0588
IL	Ameren CIPS	Gas	2008-2012	Case 07-0589
IL	Ameren IP	Gas	2008-2012	Case 07-0590
IL	Nicor Gas	Gas	2009-open	Docket No. 08-0363
MO	Atmos Energy	Gas	2007-2010	Case GR-2006-0387
MO	Atmos Energy	Gas	2010-open	Case No. GR-2010-0192
MO	Empire District Gas	Gas	2010-open	Case GR-2009-0434
MO	Missouri Gas Energy	Gas	2007-open	Case GR-2006-0422
MO	Laclede Gas	Gas	2002-open	Case GR-2002-356
MS	Mississippi Power	Electric	Occurred over period of years	No specific case
ND	Xcel Energy	Gas	2005-open	Case PU-04-578
OH	Duke Energy Ohio (CG&E)	Gas	2008-open	Case 07-590-GA-ALT
OH	Dominion East Ohio	Gas	2008-2010	Case 07-830-GA-ALT
OH	Columbia Gas	Gas	2008-open	Case 08-0072-GA-AIR
OH	Vectren Energy Delivery of Ohio	Gas	2009-open	Case 07-1080-GA-AIR
OK	Oklahoma Natural Gas	Gas	2004-open	Cause Nos. PUD 2004-00610, PUD 201000048, PUD 200900110

V. Formula Rates

A formula rate plan ("FRP") is essentially a wide-scope tracker mechanism that is designed to help a utility's revenue track its pro forma cost of service. When a company's revenue and cost are not in balance, its realized ROE deviates from the target set by regulators, and earnings surpluses or deficits occur. FRPs have earnings true up mechanisms that adjust rates so as to reduce or eliminate such earnings variances.

The earnings true up mechanism in an FRP calculates the revenue adjustment necessary to reduce or eliminate earnings variances. Some compare the earned ROE to the target (a/k/a benchmark) ROE, and then calculate the rate adjustment needed to reduce the ROE variance. Another approach is to adjust rates for the difference between revenue and a pro forma cost of service that is calculated using the ROE target. Both approaches typically add interest to the revenue adjustment. Earnings true up mechanisms in FRPs commonly move the ROE all, or almost all, of the way to its regulated target. This is an important distinction between an FRP earnings true up mechanism and the earnings *sharing* mechanisms found in some multiyear rate and revenue caps.

The earnings impacts of certain business conditions are typically handled outside of the FRP. The excluded business conditions are often addressed by separate trackers. Utilities operating under FRPs must occasionally make major plant additions. Budgets for major plant additions are generally determined outside the FRP mechanism through, for example, hearings on certificates of public convenience and necessity. Mechanisms are sometimes added to an FRP to encourage better operating performance in targeted areas. An example is an index-based limit on the escalation of O&M expenses.

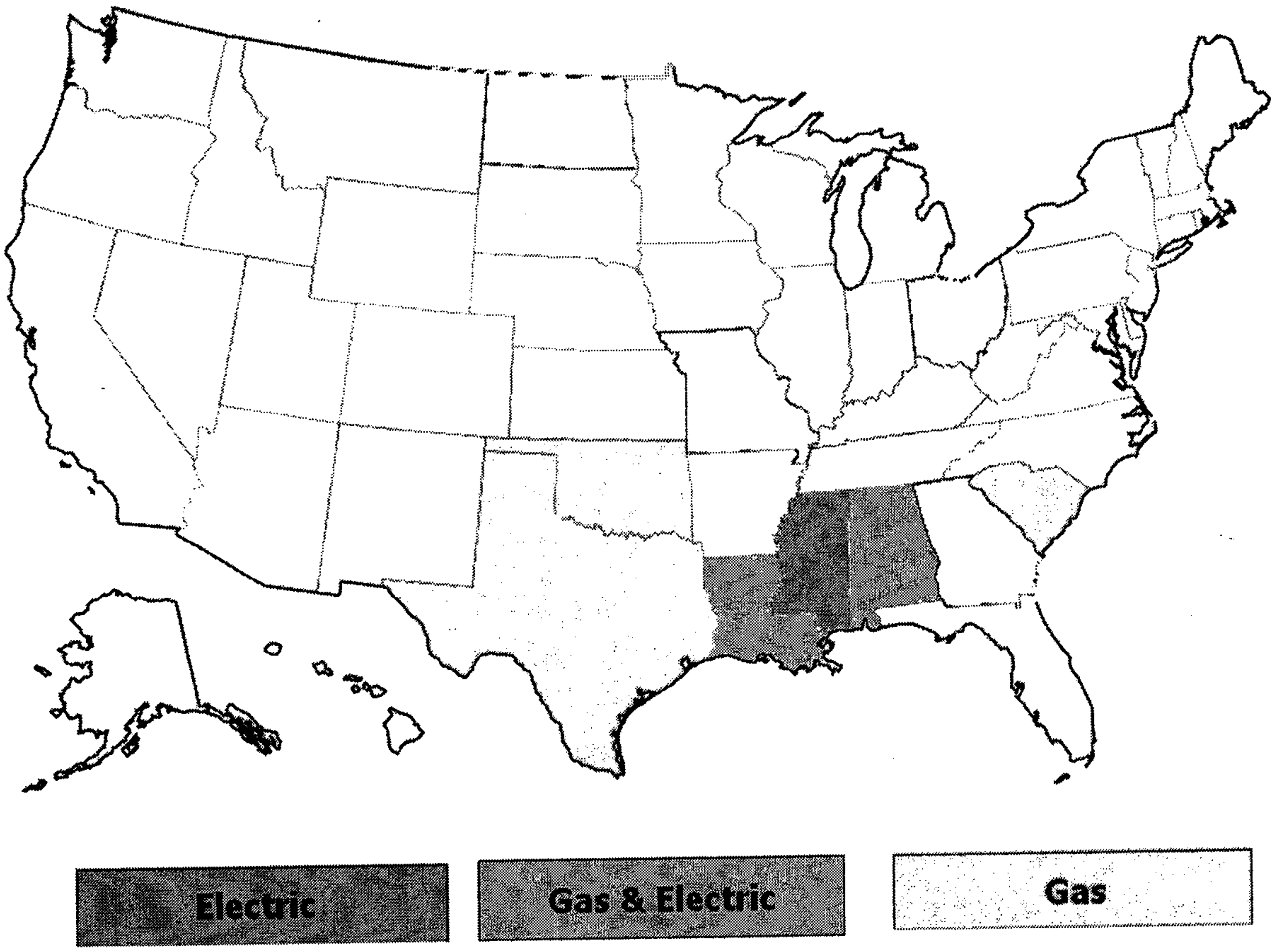
The FERC accounts for the lion's share of FRP precedents today, as it has in the past. Formula rates have been used at the FERC and its predecessor, the Federal Power Commission, to regulate interstate services of gas and electric utilities since at least 1950. Use of FRPs by the FERC was encouraged in the 1970s and early 1980s by rapid input price inflation. Despite slower inflation in recent years, the FERC's use of formula rates has rebounded in the power transmission industry, encouraged by national policies that promote transmission investment.

Precedents for retail formula rates, which recover costs of generation and/or distribution, are shown in Table 8 and Figure 7. It can be seen that formula rate plans for *retail* utility services are operative today in the Southeast and Southern Plains states. Alabama was an early innovator, approving "Rate Stabilization and Equalization" plans for Alabama Power and Alabama Gas in the early 1980s. Formula rates are, additionally, now used to regulate electric utilities in Mississippi, some gas and electric utilities in Louisiana, and some gas utilities in Oklahoma, Texas, and South Carolina. Utilities in some additional states have formula rate plans to recover their transmission costs from retail customers.

Table 8: Retail Formula Rate Plan Precedents

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2006-open	Dockets No. 18117 and 18416 (October 2005)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2006	Dockets No. 18117 and 18416 (March 2002)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1998-2002	Dockets No. 18117 and 18416 (March 1998)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1990-1998	Dockets No. 18117 and 18416 (March 1990)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1990	Dockets No. 18117 and 18416 (June 1985)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1982-1985	Dockets No. 18117 and 18416 (November 1982)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2008-2014	Dockets No. 18406 and 18328 (December 2007)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2007	Dockets No. 18046 and 18328 (June 2002)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1996-2001	Dockets No. 18046 and 18328 (October 1996)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1991-1994	Dockets No. 18046 and 18328 (December 1990)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1987-1990	Dockets No. 18046 and 18328 (September 1987)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1987	Dockets No. 18046 and 18328 (May 1985)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1983-1985	Dockets No. 18046 and 18328 (January 1983)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2009-2013	Docket 28101 (December 2009)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2005-2009	Docket 28101 (June 2005)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2001-2005	Docket 28101 (June 2002)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2006-open	Docket No. U-21484 (May 2006)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2001-2003	Docket No. U-21484 (January 2001)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Plan	2006-open	Docket No. U-28814 and U-28588 and U-28587(May 2006)
LA	Entergy New Orleans	Electric and Gas	Formula Rate Plan	2010-2012	Docket No. UD-08-03 (April 2009)
LA	Entergy New Orleans	Electric only	Formula Rate Plan	2004-2006	Docket No. UD-01-04 (May 2003)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 5 (FRP-5)	2010-open	Docket No. 2009-UN-388 (March 2010)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 5 (PEP-5)	2010-open	Docket No. 2003-UN-0898 (November 2009)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4A (PEP-4A)	2009	Docket No. 06-UN-0511 (January 2009)

Figure 7: Current Retail Formula Rate Precedents by State



VI. Forward Test Years

General rate cases involve test years in which revenue requirements and billing determinants are jointly considered in fashioning new rates. A historical test year ends before the rate case is filed. A forward (a/k/a forecasted) test year ("FTY") is a twelve month period that begins after the rate case is filed. The test year typically begins about the time that the rate case is expected to end.

Historical test years are chronically uncompensatory when cost has a tendency to grow more rapidly than billing determinants. Annual rate cases can alleviate but not eliminate underearning. Where historical test years are used in rate cases there are thus added advantages from implementing other innovations discussed in this paper, such as capex trackers, multiyear rate and revenue caps, and/or some form of revenue decoupling.

Forward test years were adopted in many jurisdictions during the 1970s and 1980s when rapid input price inflation and major plant additions coincided with slower growth in average use. Commissions in several additional states have recently moved in the direction of forward test years. Many of these states are in the West, where comparatively rapid economic growth has required more rapid buildout of utility infrastructure.

Current state policies concerning test years are summarized in Figure 8 and Table 9. The ranks of U.S. jurisdictions that use alternatives to historical test years have swollen and now encompass well over half of the total. The "other" category in Figure 8 includes states that use FTYs for some utilities and historical test years for others (*e.g.* Illinois), states that are transitioning towards forward test years (*e.g.* New Mexico and Utah), states that use hybrid test years with some but not all months forecasted (*e.g.* Pennsylvania and Idaho), and states that have used FTYs in the past but don't currently use them (*e.g.* Delaware).

Figure 8: Test Year Policy by State

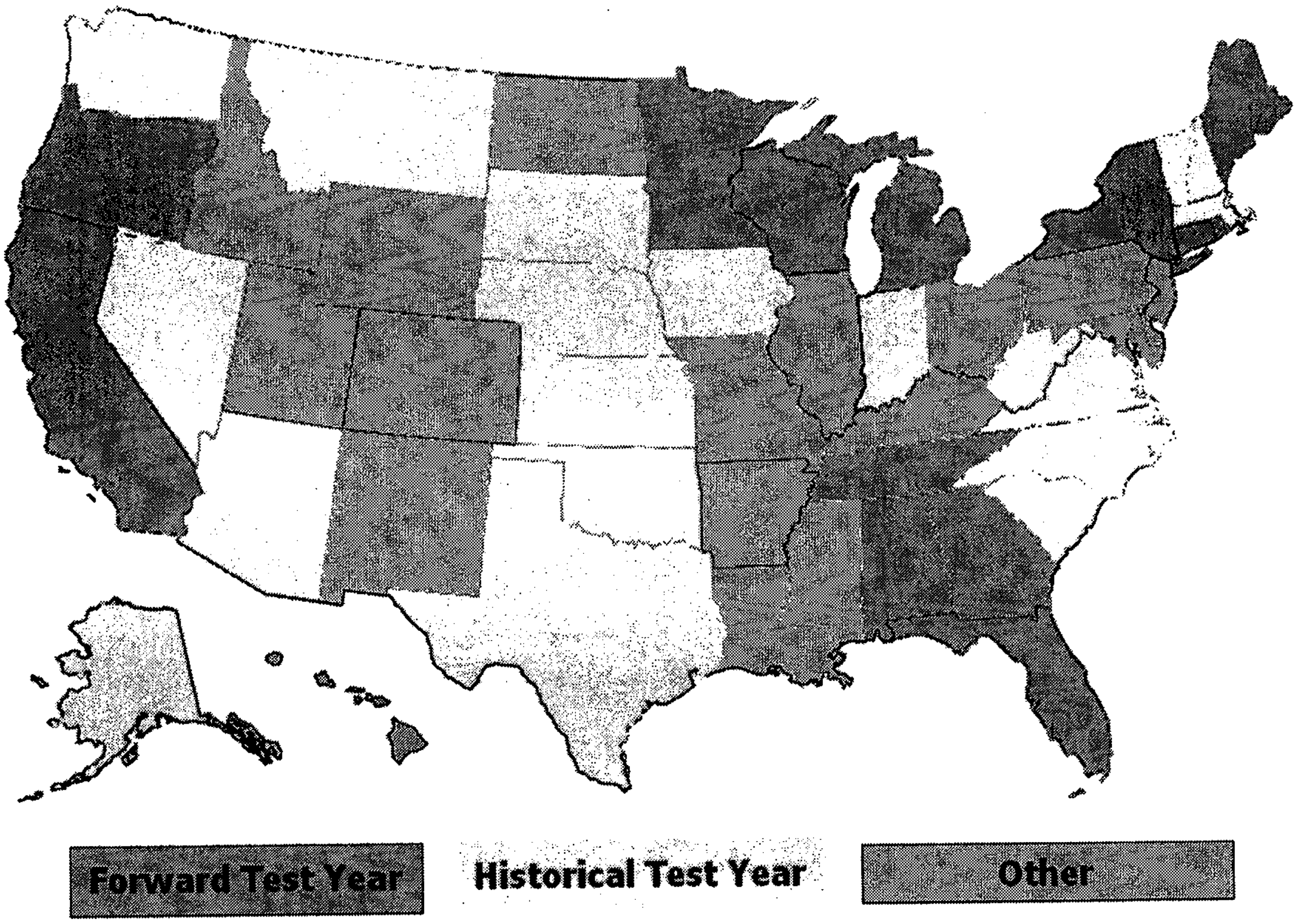


Table 9: Test Year Approaches of U.S. Jurisdictions

Forward (15)

State	Notes
Alabama	Utilities operate under forward-looking formula rate plans
California	
Connecticut	Cost is based on a historical test year that is escalated to a future rate year
FERC	Rate cases use forward test years while formula rate plans tend to use HTYs
Florida	
Georgia	
Hawaii	
Maine	Cost is based on a historical test year that is escalated to a future rate year
Michigan	
Minnesota	
New York	
Oregon	
Rhode Island	Cost is based on a historical test year that is escalated to a future rate year
Tennessee	
Wisconsin	

Hybrid (4)

State	Notes
Arkansas	
Ohio	
New Jersey	
Pennsylvania	

Transitional/Varying (14)

Utility Name	Notes
Colorado	Public Service of Colorado can file FTY evidence. No FTY rates have yet been approved but the most recent case made extraordinary HTY adjustments.
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently
Delaware	Before restructuring FTY filings were common, but companies have used HTY in recent filings
Idaho	
Illinois	Utilities use various test years including FTYs
Kentucky	Utilities use various test years including FTYs
Louisiana	Cleco Power frequently uses hybrid test years. Entergy New Orleans recently had a hybrid test year approved via settlement
Maryland	Baltimore Gas & Electric tends to file hybrid test years while other utilities tend to file historical test years
Mississippi	One electric utility operates under a forward-looking formula rate plan
Missouri	Utilities have the option to file hybrid year forecasts that are trued up during the course of the proceeding
New Mexico	A recently passed law allows for use of FTY, but no rate increase based on FTY evidence has yet been approved
North Dakota	Utilities use various test years including FTYs
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently had FTYs approved

Historical (19)

Utility Name	Notes
Alaska	
Arizona	
Indiana	
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs in its jurisdiction. Gas companies are legally authorized to use FTYs but commonly use HTYs.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

VII. Conclusions

Regulation of North American energy utilities is evolving to address the problem of regulatory lag. Innovations are occurring, and some older variants on traditional regulation are again finding favor. Approaches detailed in this report are sometimes used in combination. A capex tracker for AMI may, for example, be combined with a forward test year or a multiyear rate or revenue cap.

The variety of approaches that have been established reflects the varied circumstances of individual utilities. Some are vertically integrated, while others are more specialized power distributors. Investment needs and trends in average use vary greatly. No single approach is right for every situation. The availability of multiple remedies for the underlying problems increases the chance that an approach has already been tried that fits the situation of almost any electric utility. Numerous precedents for an approach should raise confidence that it makes good sense under fairly common circumstances.

Taken together, the many innovations described in this survey can encourage utilities to make smart investments, reduce long run costs, and improve service quality without rate shock or unnecessarily frequent rate cases. Utilities can be encouraged to promote energy efficiency and peak load management aggressively. Stakeholders to regulation across America should give priority attention to these options and consider which combination of remedies to regulatory lag works best in their situation.

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701 Pennsylvania Ave., N.W. | Washington, D.C. 20004-2696 | 202.508.5000 | www.eei.org